

DIRECT COMBUSTION OF COAL

HEARING
BEFORE THE
SUBCOMMITTEE ON
ENERGY DEVELOPMENT AND APPLICATIONS
OF THE
COMMITTEE ON
SCIENCE AND TECHNOLOGY
U.S. HOUSE OF REPRESENTATIVES
NINETY-SEVENTH CONGRESS
FIRST SESSION

DECEMBER 10, 1961

[No. 69]

Printed for the use of the
Committee on Science and Technology



U.S. GOVERNMENT PRINTING OFFICE
WASHINGTON: 1962

89-628 O

H701-39

COMMITTEE ON SCIENCE AND TECHNOLOGY

DON FUQUA, Florida, *Chairman*

ROBERT A. ROE, New Jersey
GEORGE E. BROWN, Jr., California
JAMES H. SCHEUER, New York
RICHARD L. OTTINGER, New York
TOM HARKIN, Iowa
MARILYN LLOYD BOUQUARD, Tennessee
JAMES J. BLANCHARD, Michigan
TIMOTHY E. WIRTH, Colorado*
DOUG WALGREN, Pennsylvania
RONNIE G. FLIPPO, Alabama
DAN GLICKMAN, Kansas
ALBERT GORE, Jr., Tennessee
ROBERT A. YOUNG, Missouri
RICHARD C. WHITE, Texas
HAROLD L. VOLKMER, Missouri
HOWARD WOLPE, Michigan
BILL NELSON, Florida
BERYL ANTHONY, Jr., Arkansas*
STANLEY N. LUNDINE, New York
ALLEN E. ERTEL, Pennsylvania
BOB SHAMANSKY, Ohio
RALPH M. HALL, Texas
DAVE McCURDY, Oklahoma
MERVYN M. DYMALLY, California

LARRY WINN, Jr., Kansas
BARRY M. GOLDWATER, Jr., California
HAMILTON FISH, Jr., New York
MANUEL LUJAN, Jr., New Mexico
HAROLD C. HOLLENBECK, New Jersey
ROBERT S. WALKER, Pennsylvania
EDWIN B. FORSYTHE, New Jersey
WILLIAM CARNEY, New York
MARGARET M. HECKLER, Massachusetts
F. JAMES SENSENBRENNER, Jr.,
Wisconsin
VIN WEBER, Minnesota
JUDD GREGG, New Hampshire
RAYMOND J. McGRATH, New York
JOE SKEEN, New Mexico
CLAUDINE SCHNEIDER, Rhode Island
JIM DUNN, Michigan
BILL LOWERY, California

HAROLD P. HANSON, *Executive Director*
PHILIP B. YEAGER, *General Counsel*
REGINA A. DAVIS, *Administrator*
GERALD E. JENKS, *Minority Staff Director*

SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATIONS

DON FUQUA, Florida, *Chairman*

TOM HARKIN, Iowa
JAMES J. BLANCHARD, Michigan
RICHARD C. WHITE, Texas
HAROLD L. VOLKMER, Missouri
HOWARD WOLPE, Michigan
BILL NELSON, Florida
ALLEN E. ERTEL, Pennsylvania
DAVE McCURDY, Oklahoma
ROBERT A. ROE, New Jersey
RICHARD L. OTTINGER, New York
JAMES H. SCHEUER, New York
MARILYN LLOYD BOUQUARD, Tennessee
ROBERT A. YOUNG, Missouri

HAMILTON FISH, Jr., New York
F. JAMES SENSENBRENNER, Jr.,
Wisconsin
VIN WEBER, Minnesota
JUDD GREGG, New Hampshire
JOE SKEEN, New Mexico
CLAUDINE SCHNEIDER, Rhode Island
RAYMOND J. McGRATH, New York
JIM DUNN, Michigan
ROBERT S. WALKER, Pennsylvania

*On assignment to Budget Committee for 97th Congress.

CONTENTS

WITNESSES

December 10, 1981:	Page
Dr. Thomas J. Wilbanks, Associate Director/Energy Division, Oak Ridge National Laboratory, Oak Ridge, Tenn., and Fred Johnson, Water Resources Coordinator, Pennsylvania Fish Commission, Harrisburg, Pa.....	2
H. Kerner Smith, manager, fossil power generation division, Babcock & Wilcox Co.; Tobias Anthony, Research-Cottrell, Inc.; and Kurt Yeager, director, coal combustion systems division, Electric Power Research Institute.....	33
Appendix I: Additional statement for the record from OTISCA Industries.....	75
Appendix II: Additional information for the record	81

(iii)

DIRECT COMBUSTION OF COAL

THURSDAY, DECEMBER 10, 1981

HOUSE OF REPRESENTATIVES,
COMMITTEE ON SCIENCE AND TECHNOLOGY,
SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATIONS,
Washington, D.C.

The subcommittee met, pursuant to call, at 2 p.m., in room 2318, Rayburn House Office Building, Hon. Allen E. Ertel presiding.

Present: Representatives Ertel, Skeen, and Dunn.

Mr. ERTEL. Today our hearing involves the utilization of coal through direct combustion. Such a process is well known, since it is practiced by industry, by commercial establishments, and in the home. It is so well established that it does not make the headlines, but it does account for 20 percent of the energy produced in this country. Direct combustion is the most expeditious and efficient method of using the energy in coal.

However, the use of coal does present a variety of problems. Extraction, whether by strip mining or deep mining, upsets ecology, and is a dangerous occupation. Transportation results in creating a trail of dust and in placing certain strains on our rail system. Under transportation we are talking about a coal slurry pipeline of major consequence in another committee on which I am involved. Storage of coal results in harmful water runoff. Combustion residues are blamed for such environmental problems as acid mine drainage and acid precipitation. Therefore, we realize that there are many opportunities to make coal a more attractive fuel, assuring its basic and increasing use in meeting the Nation's energy requirements.

Our witnesses today should give us good insight into first, those problems associated with the use of coal, and second, the work being done to alleviate a large number of these problems.

We look forward to hearing from these witnesses and welcome them to the committee. In the interest of time and to provide the opportunity for discussion, we ask that each of you limit your presentation to about 10 minutes. However, we certainly will enter your statements into the record in full. We hope that you will be kind enough to summarize your statements, and we will proceed from that point.

Our first witnesses are Dr. Thomas J. Wilbanks, Associate Director of the Energy Division, Oak Ridge National Laboratory, and Mr. Fred Johnson, water resources coordinator for the Pennsylvania Fish Commission in Harrisburg, Pa. We welcome you gentlemen and look forward to your telling us what you have to tell us. [The biographical sketch of Dr. Wilbanks follows:]

DR. THOMAS J. WILBANKS

Dr. Wilbanks is Associate Director and Head of Programs and Planning for the Energy Division of the Oak Ridge National Laboratory. Formerly a faculty member and administrator at Syracuse University and the University of Oklahoma, he has authored or co-authored four books or monographs and a variety of other published papers on technology assessment, impact assessment, decisionmaking, and other topics. He has served as a member of several national panels and committees, including the Committee on Behavioral and Social Aspects of Energy Consumption and Production of the National Research Council; a consultant to government agencies; and a contributor to several studies by the Office of Technology Assessment.

STATEMENTS OF DR. THOMAS J. WILBANKS, ASSOCIATE DIRECTOR/ENERGY DIVISION, OAK RIDGE NATIONAL LABORATORY, OAK RIDGE, TENN., AND FRED JOHNSON, WATER RESOURCES COORDINATOR, PENNSYLVANIA FISH COMMISSION, HARRISBURG, PA.

Dr. WILBANKS. Mr. Chairman and members of the subcommittee, I want to thank you for this chance to be here again and to be a part of this discussion of such an important subject. Because my colleague on the panel, Mr. Johnson, is going to be talking about environmental issues associated with coal use, I thought I would focus my comments this afternoon on some of the broad economic issues, because they are a central part of any discussion of increasing the use of coal through direct combustion. In doing this, I will be speaking as a private citizen, of course, not as a representative of the Oak Ridge National Laboratory or the Department of Energy.

My written testimony starts out with a very brief summary of what is going on in our use of coal in this country, but I am going to skip that except to say that our use of coal is increasing steadily but not very fast; three-quarters of it is now going to generate electricity; a larger and larger percentage of it is being used in very large facilities; a large percentage of it is used in relatively few States; and a lot of it is being used in old facilities, due to be replaced in the 1980's if they are not past due already.

In short, we have abundant coal resources in this country. We have technologies for using coal in ways that comply with all of our current standards for environmental protection. Coal is very cheap compared with oil—and pretty cheap right now compared with nuclear energy, solar energy for many purposes, and even natural gas—at least if it is assumed that gas prices are going to be deregulated in the 1980's. So why are we not using more coal? Increasing its use faster?

That is what I am going to talk about. Clearly, a lot of hard-headed, pragmatic decisionmakers in utilities and industry are taking a look at coal in this very uncertain time we are living in, and they are saying: "No. Not now. Not yet. We'll do something else for now."

What I am going to do is suggest five reasons for this kind of decision right now, and then—very briefly—I will comment on some additional issues that are going to arise if conditions change in the next several years so that our rate of coal use increases significantly.

In talking about these kinds of things, I am going to distinguish between two different kinds of opportunities for coal use: First, op-

portunities associated with expanding production—adding new facilities to meet new needs, and second, opportunities associated with replacing or retrofitting existing facilities that meet existing needs. I will call these the “expansion market” and the “replacement market.”

The first reason why potential coal users are cautious right now has to do with the expansion market, which consists very largely of additions to the generating capacity of electric utilities. As you know, there are plenty of uncertainties these days about future levels of electricity demand. Increasing the energy efficiency of buildings, for example, is a very attractive alternative to paying higher prices for electricity, and I think there is some evidence that we are just beginning to get organized to take advantage of these kinds of potentials for energy conservation in this country. As a result, utilities are scaling down their plans for additional plants, and projected new coal plants are being canceled or delayed as well as nuclear plants. Some people believe that economic recovery is going to push our rates of growth in electricity demand back to close to historic rates, but we need to remember that it will also make it easier for people to invest in improved energy efficiency. So the main expansion market for the direct use of coal is sort of soft, sort of uncertain.

The second reason applies mainly to the replacement market. I think just about everybody recognizes that we are going to have to retire existing plants—and not just coal-fired ones—at a faster rate in the 1980's than we did in the late 1970's, because we are stuck with a great deal of inefficient old capital stock. But consider a utility or industry executive with an old plant that needs replacing. He or she prefers oil or gas to coal to start with, because coal is less convenient. Interest rates have gone sky high, which puts coal at a disadvantage compared with gas or oil because coal-burning is much more capital-intensive. Meanwhile, oil prices have stopped climbing. We hear optimistic reports about our potentials for domestic natural gas production. And so on. It is pretty tempting to wait until the situation stabilizes a little before trying to decide what makes sense. Besides, even though the old unit is expensive to operate, it is probably paid for, and this is a tough time to go looking for new capital. Now, these replacement decisions are piling up in this country, and we will need to be making a lot of them in the next 10 years; but it is not entirely clear yet how many of them will be to go to coal.

Third, also related to the replacement market, we are going through a change of signals about the importance of reducing our use of oil and gas in this country. Rather than the Government pushing the conversion of oil and gas units in utilities and industry—mainly to coal—we are moving toward a policy of leaving this decision to the marketplace. This means that the actual rate of increase in direct coal use in the 1980's and 1990's is likely to be less than people were targeting a couple of years ago.

Fourth, related to both the expansion and the replacement markets, I think we need to consider whether we want the direct use of coal to be essentially limited to large facilities in the future. This is the clear trend, reflecting economies of scale that were moving things in this direction long before the environmental regulations

of the 1970's—and reinforced by the economies of scale in complying with these regulations now, using the standard control technologies. This trend represents a significant constraint on the role coal plays in our economy, and I think the only way to ease it is to consider some technology options that are not widely used at present. One option is to provide smaller users with clean coal and allow them to burn it without stack-gas cleanup. A second is to go to syn-fuels—say, using gasification as a coal cleanup approach for a small region and then distributing the energy from coal as a clean gas. A third is the use of more advanced technologies, either for emission controls or for coal combustion. Fluidized bed coal combustion is one such option; but it has the problem that most potential users still see it as an experimental technology, a bunch of one-of-a-kind prototypes. Going to it now seems to many people to be a little like being the first person to buy a new model car when the automobile magazine on the rack in the drug store says the technology still has some bugs in it. A fourth option is some of the recent experiments with pulverized coal, especially as a replacement fuel for oil: superfine ground coal by itself, or mixed with oil, or combusted as a coal-water mixture—an approach that may turn out to be very attractive if it tests out successfully in the next several years.

Fifth, the environmental rules of the game that will be in effect over the lifetime of a new coal facility are exceedingly uncertain right now, and this uncertainty affects the relative attractiveness of coal as an energy option to a risk-averse decisionmaker at this point. Let me give three examples: (A) There are signs of a changing philosophy toward environmental controls in this country—not so much a relaxation of our concerns about environmental quality, in my opinion, as a fairly widespread interest in the economic value and the scientific validity of allowing a little more flexibility in the way we define and apply standards and requirements. With the outcome of this discussion still up in the air, it probably makes sense for a prospective coal user to wait and see what happens. (B) Scientists are still not in agreement about the health and environmental effects of the various wastes from coal combustion, and research continues on this. For the potential coal user, this opens up the very real possibility that scientists are going to find that some presently unregulated substance is in fact hazardous, which would mean difficult retrofits of new control equipment somewhere down the line. This problem is one that is not going to go away very soon, and I think it is a bigger one for coal than for any of our other major energy options. (C) Although we know a lot about the capabilities of control technologies when they work the way they are supposed to, we all know that there is still some uncertainty about how reliable and efficient they will be over the long haul. This has surfaced as an important issue in environmental impact assessments for coal facilities, and it affects not only the acceptance of a new facility by people in the local area but also the estimates by operators of maintenance costs and the reliability of their energy supply equipment in the future.

Well, I think these kinds of things are very real challenges to a policymaker who wants to speed up the direct use of coal in the United States. But let us suppose that the necessary things happen

so that the direct use of coal doubles or triples by sometime in the 1990's. What additional issues would we have to deal with then? I think four should be mentioned here.

The first is the following. The absolutely superb report by the Office of Technology Assessment a couple of years ago on the direct use of coal said that a major increase in our use of coal will certainly have some environmental impacts—some because of conscious decisions about economic tradeoffs, some because control devices do not work as well as hoped, some because of insufficient enforcement of standards, and so on. These kinds of cumulative impacts could create increasing pressure for us to reconsider our commitment to coal use in the United States, and I think it is in this context that the ongoing research on CO₂, acid rain, and health impacts of coal wastes is especially important. But one point I would make about this is that, if there is such a threshold of maximum acceptable cumulative impacts from coal use, the way we hold it back is by doing our very best to use coal carefully and cleanly now.

The other three issues I will simply list because of the time: (1) if we develop a pattern of coal use that involves a lot of smaller facilities, we will need to develop a kind of local infrastructure for coal storage, distribution, and waste disposal that may be tough to manage in an environmentally sound way; (2) if we do not involve a lot of smaller facilities in this growth, we will probably face some serious problems with the very much greater number of large facilities: facility siting, the need for new transmission lines, and so on; and (3) the supply end of this rate of growth in coal use will eventually require a lot more leasing of coal on Federal lands, which I think needs no elaboration these days.

In summary, we are using more coal than we used to in the United States, but our domestic coal is still an underutilized resource. The reasons include uncertainties about future electricity by demand; uncertainties about the economic attractiveness of coal compared with oil, gas, and conservation; our frequent changes in Government policy toward coal use; the increasing limitation of coal use to large facilities; and a whole host of uncertainties about environmental and health impacts and society's response to them. In my personal opinion, these challenges are no reason to be pessimistic about the future of coal in this country, but they do suggest to me that the Federal Government is going to have to stay actively involved in coal research and policymaking if we are going to have much of a chance of realizing the potential of this great domestic energy resource.

Thank you.

[The prepared statement of Thomas J. Wilbanks follows:]

THOMAS J. WILBANKS

Associate Director
Energy Division
Oak Ridge National Laboratory
Oak Ridge, Tennessee 37830

TESTIMONY

Presented to the Subcommittee on
Energy Development and Applications,
Committee on Science and Technology,
U.S. House of Representatives

Hearing on Issues Associated
with Direct Coal Combustion

December 16, 1981

7

TESTIMONY TO THE SUBCOMMITTEE
ON ENERGY DEVELOPMENT AND APPLICATIONS,
U.S. HOUSE OF REPRESENTATIVES
DECEMBER 1981

MR. CHAIRMAN, DISTINGUISHED MEMBERS OF THE SUBCOMMITTEE:

Thank you for this chance to be here again and to be a part of this discussion of an important subject. After talking with your fine staff about the specialties of the others scheduled to give testimony today, I decided that the most useful contributions I could make might be of two kinds: (1) to provide a little background for the discussion of what needs to be done by trying to summarize what's happening now, and (2) to raise a few issues that are broader in scope than many of the specific environmental issues, such as emission controls and acid rain, that I expect will be addressed by my colleagues on the panel. By the way, I need to make clear that my testimony is presented as a private citizen, not as a representative of the Oak Ridge National Laboratory or the Department of Energy.

A. What Is Going On

We are already using more coal than we once did. Coal consumption in the United States in 1980 was half again as much as it had been twenty years before--and up more than 20 percent from five years before.* Over this 20 year period, the average annual rate of growth was not very high (on the order of two percent a year); but since 1975 we have resumed the steady upward trend that had been lost between the mid-1960's and mid 1970's.**

*Table 1 (all tables are appended at the end).

**1978 showed a slight drop from 1977, but the reason was a prolonged coal strike. Partly because of the need to refill stockpiles, coal use grew at the unusually high rate of 9 percent in the following year.

Hidden within these overall figures are two major changes in how we use coal in the United States:

(1) Three quarters of the coal we consume in this country now goes to generate electricity--a big change. In 1960, more coal was used by industry than by electric utilities. By 1980, three times as much was consumed to make electricity as it was to produce steam and generate process heat and provide for other energy needs in industry.* In the same twenty years that utility use of coal increased by more than 2 1/2 times, industrial use dropped by a quarter (although it stabilized in the late 1970's) and residential and commercial uses of coal dropped by 80%.** That's a significant shift, and as a result it's no surprise that our thinking about coal use is so dominated by the plans of the utilities.

(2) More and more, coal has become a fuel for very large facilities. For example, half of the coal-fired electricity generating units built during the 1950's were smaller than 100 MW(e) in capacity. By contrast, nearly two-thirds of the new coal-fired units projected for the near future by the electric utilities are larger than 500 MW(e) in capacity (many much larger).*** For a number of reasons, continuing a trend that started well before complying with environmental standards became such a factor, the economies of scale in coal use have grown to a point where they have a very heavy influence on energy supply decisions.

These two changes are a big part of the story, but I would like to mention three other parts as well:

*Table 1. Note that in every year of the past twenty, coal consumption by utilities increased at a faster rate than coal consumption overall.

**Table 2.

***Table 4.

(1) Although coal is truly a national resource, available in most parts of the country, it is still essentially a regional fuel. Forty-one percent of the coal we used in 1979 was consumed in five contiguous states (30 percent of it in three states: Pennsylvania, Ohio, and Indiana).*

(2) There are some signs that the domestic production of coal is starting to decouple from the domestic use of coal. Coal production went up 24 percent between 1978 and 1980, while coal consumption in the U.S. went up less than 13 percent.** Maybe it's not essential to resolve all the uncertainties about future U.S. coal demand before we decide to proceed with developing more of our domestic coal resources. Other countries will provide markets for whatever coal we choose not to consume ourselves.

(3) An interesting characteristic of our pattern of coal use is that it involves a very large number of old facilities. For instance, more than 57 percent of the coal-burning units generating electricity in 1980 were more than 20 years old; 21 percent were more than 30 years old, and 5 percent were older than I am (which means they started operating before 1938).*** Most of these units are small--many very small--but they are important for two reasons: (a) they are generally inefficient and certainly contribute much more than their share to the environmental pollution associated with coal use, and (b) during the 1980's we will need to be taking actions to replace these units, either with newer and better coal-burning facilities or something else. Furthermore, most of the non-coal-burning facilities that could be converted relatively easily to coal are old. The list of orders requiring fuel conversion issued under provisions

*Table 6.

**Table 3.

***Table 4; also see Table 5.

of the Energy Supply and Environmental Coordination Act included 107 electricity generating units. As of last year, according to the Congressional Research Service, 88 of these were 15 years old or older, and 73 were 20 years old or older. It was estimated that anywhere from 15 to 40 percent of the units would not be converted due to age; if necessary, they would be retired instead. Balancing our picture of big, new, coal-fired power plants, therefore, should be another picture of small old workhorse units, kept going well past the normal lifetime of the equipment by replacing components, doing ad hoc repairs, and generally trying to put off a decision about what to do for the next 30 or 40 years.

B. Why We Aren't Increasing the Direct Use of Coal Faster

This leads me to the next part of my comments. Clearly, we have abundant coal resources in this country; we have technologies for using coal in ways that comply fully with current standards for environmental protection; and coal is very cheap, compared with oil--and pretty cheap right now compared with gas, nuclear energy, and solar energy for many purposes. So why aren't we all rushing to use it?

I think there are some very important reasons why many people in a position to make decisions about coal use are saying that this is not the time to make a long-term choice to consume coal,* and I would like to suggest five of them here. In talking about these reasons, I will be distinguishing between two different kinds of opportunities for coal use:

(a) opportunities associated with expanding production--adding new

*There are some exceptions, of course: for example, firms that own their own coal or firms that decide to use coal to reduce risks associated with some other very large capital investment (e.g., a long-term requirement for large quantities of process heat).

facilities to meet new needs--and (b) opportunities associated with replacing or retrofitting existing facilities. I will call these the "expansion market" and the "replacement market."

(1) The first reason for caution has to do with the expansion market, which consists very largely of additions to the generating capacity of electric utilities. As you know very well, there are considerable uncertainties these days about future levels of electricity demand. Increasing the energy efficiency of buildings is a very attractive alternative to paying rising prices for electricity, and there is some evidence that we are just beginning to get organized to take advantage of our potentials for buildings energy conservation in this country. As a result, utilities are scaling down their plans for additional plants, coal as well as nuclear. For example, the 1979 Inventory of Power Plants in the United States projected the addition of more than 150,000 MW(e) of additional coal-fired capacity; the 1980 Inventory projected only about 120,000 MW(e).^{*} Some of the difference, of course, was plants projected in 1979 that came on line in 1980, but the 1980 Inventory showed 46 coal-fired units as cancelled or postponed--27 of a size of 500 MW(e) or larger.^{**} Some people believe that economic recovery will restore rates of growth in electricity demand that are close to our historic rates, but we need to remember that it will also make it easier for people to invest in improved energy efficiency.

(2) The second reason applies mainly to the replacement market. Everybody recognizes that the retirement rate of existing plants is going to have to increase in the 1980's, because we are stuck with so much

^{*}Table 7.

^{**}Table 4.

inefficient old capital stock; but it turns out that there are more uncertainties in 1981 about the extent of the economic advantages of coal over oil and gas than there were in, say, 1979. There is new optimism about domestic gas production potentials, for example, and oil prices have stopped climbing. Meanwhile, interest rates have gone sky-high, which puts coal at a disadvantage compared with gas or oil because coal-burning is much more capital-intensive. To a utility or industry executive who prefers oil or gas anyway, because the direct combustion of coal is less convenient (associated in his or her mind with such disadvantages as materials handling, forms, and regulations), this makes it tempting to wait until the situation stabilizes a little bit before deciding what route to take in replacing or retrofitting existing equipment. Besides, even though the operating costs of the old unit are relatively high, the capital costs are largely paid for, and this is a tough time to go looking for new capital. It's likely that the deregulation of natural gas prices will encourage more coal use, but some people in industry are saying that gas prices will have to double before they will pick coal--as long as they are reasonably sure of gas supply for the lifetime of the new facility.

(3) Also related to the replacement market, we are going through a change of signals about the importance of reducing our use of oil and gas. Rather than pushing the conversion of oil and gas units in utilities and industry--largely to coal--by government mandate or incentives, we are moving toward a policy of leaving this decision to the marketplace. This means that the forecasts of increased coal use that were prepared during the Carter administration, which assumed a lot of fuel switching, must now be considered at least uncertain, and probably unlikely. For instance,

federal assistance with the capital costs of retrofits would make a significant difference in coal use in the United States, but the prospects for that to happen are poor.

(4) Related to both the expansion and replacement markets, we need to consider whether we want the direct use of coal to be essentially limited to large facilities. This is the trend in the marketplace. Even though smaller units are exempted from many environmental control requirements, they are still subject to the economies of scale that began the shift to larger facilities in the 1960's. For medium-sized facilities which are subject to environmental regulations, the economies of scale are magnified by the cost of compliance. For example, a coal-burning facility above a certain size is required by law to maintain continuous scrubbing of sulfur from stack gases; this means that backup scrubbing modules have to be available in case a main unit goes down. These modules are simply not available in small sizes. As a result, where in principle a facility can get by with a 25 percent backup (or "sparing") capability, a relatively small facility might have to pay for 50 percent sparing because it cannot buy anything smaller. This sort of thing represents a significant constraint on the role coal plays in our economy. By the way, there are several possible ways to ease this constraint if we want to. One is to provide small users with clean coal and allow them to burn it in new plants without stack gas cleanup. A second is through synfuels--say, using gasification as a coal cleanup approach for a small region and then distributing the energy from coal as a clean gas. A third is the use of more advanced technologies, either for emission controls or coal combustion; fluidized bed coal combustion is one such option (although it seems to many potential

users still to be an experimental technology, not a proven, standardized, off-the-shelf option). A fourth is some of the recent experiments with pulverized coal, which may offer us some ways to substitute coal for oil with a minimum of trouble. As you know, there have been tests with superfine ground coal, with coal-oil mixtures, and with coal-water mixtures as well. Some relatively small-scale tests of coal-water mixtures indicate that they might be usable in oil burners without too much modification--potentially a very attractive way to use what comes out of the end of a slurry pipeline.

(5) The environmental rules of the game that will be in effect over the lifetime of a new coal facility are exceedingly uncertain. In terms of individual decisions right now about whether to use coal, I think nearly everybody agrees that there is no fundamental conflict with current environmental regulations; that's not the issue, although the costs of compliance affect the economic comparisons of options I have already mentioned. The issue is that there are still several kinds of uncertainties about environmental impacts and society's attitudes toward them, uncertainties that affect the relative attractiveness of coal as an energy option in 1981 and 1982: (a) there are signs of a changing philosophy toward environmental controls in this country--not so much a relaxation of our concerns about environmental quality, in my opinion, as a recognition of the economic value and scientific validity of allowing a little more flexibility in the application of standards and requirements. The National Coal Policy Project, for instance, suggested that inflexible absolute limits on emissions discourage the introduction of new, probably better coal combustion technologies, because of uncertainties about their performance; and some recent work at Oak Ridge National Laboratory shows that a point source emission

standard based on a small but nonzero probability of exceeding a standard level would probably reduce the costs of stack gas cleanup substantially, compared with a standard that permits no deviations whatsoever. With such things under discussion, it probably makes sense for a prospective coal user to wait to see what the outcome will be. (b) Scientists are still not in agreement about the health and environmental effects of the various wastes from coal combustion, and research continues on this. For the potential coal user, the problem is not just that he or she may end up buying expensive control devices that turn out to be unnecessary; it's also possible that scientists will find that presently unregulated substances are hazardous, requiring difficult retrofits of new control equipment somewhere down the line. This problem is one that will not go away very soon. (c) Although we know a lot about the capabilities of control technologies when they work the way they are designed to, we have to recognize that there is still some uncertainty about how efficient and reliable they will be over the long haul. This has surfaced as an important issue in environmental impact assessments, and it raises questions not only from potentially impacted people in the vicinity of a proposed facility but also from operators who might face repair and maintenance costs and even plant shutdowns in the future.

What If the Rate of Coal Use Begins to Increase?

These kinds of things are very substantial challenges to a policymaker who wants to speed up the direct use of coal in the United States. But let's suppose that enough of the challenges are met so that the direct use of coal doubles or triples by some time in the 1990's. What additional issues might we have to deal with then? I think at least four of them need

to be a part of our discussion here, although I won't have time to elaborate on them very much:

(1) As the superb report by the Office of Technology Assessment on the direct use of coal indicated a few years ago, a major increase in our use of coal will certainly have some adverse environmental impacts--some because of conscious decisions about economic tradeoffs, some because control devices don't work as well as hoped, some because of insufficient enforcement of standards, and so on. These kinds of cumulative impacts could create increasing pressure for us to reconsider our commitment to coal use in the United States, and I think it is in this context that the ongoing research on CO₂, acid rain, and health impacts of coal wastes is especially important.

(2) Although I think we will be able to handle the mine to market transportation of coal, even with the much larger amounts that would be involved,* any pattern of coal use that involves a considerable number of smaller facilities is going to require a kind of local storage and distribution system that no longer exists in very many places in this country. A new kind of local infrastructure will have to be developed, and this is no small task, given what we have learned since the 1950's about handling coal in an environmentally sound way (e.g., runoff from coal storage piles).

(3) If we don't involve a lot of smaller facilities in this growth, we are likely to face some problems with the increasing number of large facilities: challenges in siting them, even bigger challenges in building new transmission lines for coal-burning electricity-generating plants located in remote areas, and maybe some inefficiencies because (on the

*The biggest issue will probably be impacts on communities along the way, which receive little or nothing in the way of benefits in exchange for increased congestion, noise, and other local costs.

average) a very large unit has to be shut down a larger percentage of the time for maintenance than a small one.

(4) If we increase our coal use as much as I am talking about now, and especially if our coal exports continue to grow at the same time, we will have to make more use of coal on federal lands, which means that coal leasing will become a larger and larger role of the federal government. Like the other long-term issues, this, of course, is something we can be getting ready for now.

Summary

In summary, we are using more coal than we used to in the United States, but our domestic coal is still an underutilized resource. The reasons include uncertainties about future energy demand; uncertainties about the economic attractiveness of coal compared with oil, gas, and conservation; our frequent changes in government policy toward coal use; the increasing limitation of coal use to large facilities; and a whole host of uncertainties about environmental and health impacts and society's response to them. If we resolve these factors so that coal gets to where it is used much more widely in our economy, we will still face some further issues; and we need to be working now to improve our technology and information base in case that happens.

In my personal opinion, these challenges are no reason to be pessimistic about the future of coal in this country, but they suggest to me that the federal government will have to continue to be actively involved in coal research and policymaking if we are going to realize the potential of this great domestic resource.

Table 1. Coal Consumption in the United States, 1960-1980, in Trillion Btu (1960-79 figures from State Energy Data Report, Energy Information Administration, 1981; 1980 Figures from Monthly Energy Review, Energy Information Administration, September 1981).

Year	Total Consumption of Coal	Percentage Change from Previous Year	Utility Consumption of Coal	Percentage Change from Previous Year
1960	10,119.2		4245.1	
1961	9,889.4	-2.3	4370.8	+3.0
1962	10,175.3	+2.9	4636.4	+6.1
1963	10,694.1	+5.1	5063.7	+9.2
1964	11,246.4	+5.2	5393.8	+6.5
1965	11,886.4	+5.7	5835.1	+8.2
1966	12,478.7	+5.0	6315.4	+8.2
1967	12,238.7	-1.9	6457.5	+2.3
1968	12,657.0	+3.4	7005.9	+8.5
1969	12,719.9	+0.5	7229.4	+3.2
1970	12,663.7	-0.4	7238.0	+0.1
1971	12,042.1	-5.2	7308.3	+1.0
1972	12,447.5	+3.6	7819.2	+7.0
1973	13,302.3	+6.9	8659.6	+10.8
1974	12,879.8	-3.2	8537.9	-1.4
1975	12,824.9	-0.4	8788.9	+2.9
1976	13,736.2	+7.1	9723.0	+10.6
1977	13,973.7	+1.7	10250.8	+5.4
1978	13,860.4	-0.8	10250.3	0.0
1979	15,109.0	+9.0	11262.7	+9.9
1980	15,603.	+3.3	12127.	+7.7

Table 2. Coal Consumption in the United States by Sector in Selected Years, in Trillion Btu (from State Energy Data Report, Energy Information Administration, 1981).

Year	Sector			
	Residential	Commercial	Industrial	Utility
1960	437.2	629.7	4725.9	4245.1
1965	273.7	394.9	5365.0	5835.1
1970	169.3	247.9	5000.6	7238.0
1975	96.0	142.3	3797.1	8788.9
1979	81.6	128.8	3636.0	11262.7

Table 3. Coal Consumption Trends Compared with Coal Production Trends, 1973-1980 (sources same as Table 1).

Year	Coal Consumption in the United States		Coal Production in the United States	
	Amount, in Trillion Btu	Percentage Change from Previous Year	Amount, in 1000 Short-Tons	Percentage Change from Previous Year
1973	13302.3		598,568	
1974	12879.8	-3.2	610,023	+ 1.9
1975	12824.9	-0.4	654,641	+ 7.3
1976	13756.2	+7.1	684,913	+ 4.6
1977	13973.7	+1.7	697,205	+ 1.8
1978	13860.4	-0.8	670,164	- 3.9
1979	15109.0	+9.0	781,134	+16.6
1980	15603.0	+3.3	829,700	+ 6.2

Table 4.

Coal-Burning Electric Generating Units, 1980, by Age and Capacity (compiled from Inventory of Power Plants in the United States: 1980 Annual, Energy Information Administration, 1981). Included are all units listing a form of coal (including lignite) as the primary fuel; units reported as retired, standby, or shut down are not included, nor are two units (6.5 and 27 MW) for which ages were not reported.

AGE	NAMEPLATE RATING MW			
	Less than 10 MW	10-99 MW	100-499 MW	500 or more MW
More than 30 years old	114	143	7	0
21-30 years old	40	184	222	40
11-20 years old	17	76	146	36
6-10 years old	8	17	34	69
0-5 years old	0	10	48	73
Projected	0	16	74	141
Cancelled or postponed	0	4	15	27

Table 5.

Age of Major Coal-Burning Installations in the United States, 1975 (compiled from a survey of Major Fuel-Burning Installations, Federal Energy Administration). Such installations are defined as those units other than power plants whose boilers, burners, or combustors have a design firing rate of 100×10^6 Btu's per hour or greater, individually or in combination (G. Samuels and P. E. Johnson, "A User's Review of the Major Fuel-Burning Installation Survey," ORNL/TM-6530, Oak Ridge National Laboratory, December 1978).

Age in 1975	Number*	Cumulative Percentage
More than 50 years old	26	1.9
41-50 years old	111	9.9
31-40 years old	284	30.6
21-40 years old	435	62.1
11-20 years old	308	84.5
0-10 years old	214	100.0

*Of a total of 1378 reporting the age of the installation.

Table 6. The Largest Coal-Consuming States, 1979 (from State Energy Data Report, Energy Information Administration, 1981)

State	Coal Consumption in Trillion Btu	Cumulative Percentage of the National Total
Pennsylvania	1720	11.4
Ohio	1662	22.4
Indiana	1170	30.1
Illinois	852	35.8
West Virginia	825	41.2
Michigan	759	46.3
Alabama	662	50.6
Texas	616	54.7
Kentucky	611	58.8
North Carolina	560	62.5
Tennessee	545	66.1

Table 7. Projected New Coal-Fired Electricity Generating Capacity, U.S. Electric Utilities, in MW(e), as Reported in the Annual Inventory of Power Plants in the United States (Energy Information Administration, 1979 Annual and 1980 Annual).

Federal Region	Projected in 1980	Projected in 1979
1	568	568
2	3,748	3,560
3	4,733	12,447
4	34,387	34,449
5	20,243	25,916
6	23,614	34,698
7	8,233	12,074
8	14,638	23,008
9	10,249	6,903
10	115	675
Total	120,528	154,298

Mr. ERTEL. Thank you very much, Dr. Wilbanks. You certainly have raised a lot of issues and given us a good overview of the problems. If you will be patient, we would like to turn to Mr. Johnson at this time, returning to you later. Mr. Johnson is with us, from the Pennsylvania Fish Commission and is a noted central Pennsylvania environmentalist. Welcome.

Mr. JOHNSON. Thank you, Congressman Ertel. I speak for an autonomous State agency, one of the few in the United States fish commissions which are autonomous.

Pennsylvania is not only underlain by 80 billion tons of coal, 30 billion of which is proven recoverable, but our forests, farms, and streams support several of the State's most important industries. We must balance the expansion of the present extraction of 80 million tons annually—third highest in the Nation—with possible damages to our farming, lumber, hunting, fishing, and tourism industries.

Our State was a leading coal producer throughout most of the past two centuries, peaking at over 160 million annual tons in the 1920's. We recognize the urgent need to produce and consume coal as expeditiously and efficiently as possible, without causing further damages to our other resources and the health of our citizens. Failure to properly balance these needs in the past has resulted in the extreme degradation of over 3,000 of the State's 17,000 miles of principal streams as a result of mine acid drainage and mining sediments. Applying this ratio to the State's 45,000 total stream mileage equates to over 7,900 miles of stream and river unsuited for most uses. After over 20 years of reclamation effort, this loss has been reduced by about 30 percent—to 2,200 miles of major streams and rivers. Most of these are mountain streams, whose

"opportunity lost" annual value for a typical mile of fishery is \$45,000.

Estimates for reclaiming the quarter million acres of unreclaimed strip mine land in the State so they no longer pose environmental problems range from \$5 billion to \$15 billion; reclaiming them to usefulness for other purposes such as agriculture, industry, and recreation would cost far more. This is why the new mining legislation enacted during a previous administration must not be watered down.

Mentioning two aspects of that Federal legislation. Transportation provides legislation for haulroads and bridges. At the present time, without these regulations we are in trouble, and this is a source of much sediment and erosion. Disposal. There is a method of disposal under test now which involved 50 percent fly ash with 50 percent spoils mixed upward to the full weight of the coal removed. This should be closely monitored for possible seepage effects on the receiving waters.

But, even as we continue the struggle to head off an increase of the type of losses which have blighted our land and waters for so long from below the surface, we now discover that the threat from above may soon cause even greater losses.

Pennsylvania, downwind of the Ohio Valley, the Nation's greatest industrial complex, which indeed includes our own steel capital of Pittsburgh, receives, not surprisingly, what is probably the most acidic precipitation in the world. The EPA has predicted that, based upon existing legislation for the control of sulfur and nitrogen emissions, and predicted increase in coal consumption, the amount of those substances entering the air will increase through 1995, even if "best available controls" are practiced. Even if it does not get any worse, or if emissions were to decrease somewhat, our situation is still critical.

I hope this subcommittee will listen to other authorities on the subject of acid damages to crops, forests, paint, concrete, deposition of metals, and endangerment of human health, and will limit my remarks to the subject which I know best—fish—the miner's canary for our human population.

I speak both as an angler and a scientist. The former role allows me a touch of emotionalism; the latter keeps me honest.

The acidity of any lake or stream is the result of the interaction of the pH of the ultimate source, rainfall, or snow—overlooking dry deposition—and what happens to that drop of water or snowflake from the time it hits the ground until it enters the lake or stream. The alkalinity of the soils and the bedrock of the watershed have a varying capacity to buffer or neutralize the acid in the precipitation. This ability can vary greatly, even in adjacent basins. In Canada, Scandinavia, and the Adirondacks, where many lakes and streams have already been acidified in the last decade or so to the extent that they no longer support game fish, the glaciated soils are thin and the bedrock is predominantly granite and quartz.

Fortunately for us in Pennsylvania, many of our valleys are underlain with limestone deposits, whose ability to buffer the deadly rain is almost infinite. However, when we leave the valleys for the rolling Appalachian mountains, the limestone gives way to shale and sandstone bedrock, and the soils become much thinner. While

these offer considerably greater protection than the granites and gneisses to our north, their buffering capacity, as we are sadly discovering, is far from infinite. I like to think of it as having been given a decade or two of grace to try to save our valuable mountain resources.

It is our low-order smaller, mountain streams, those pristine gems which are the home of our prized wild brook and brown trout, which are now in the front lines of the battle being fought by utilities and industry against those whose concerns and careers are linked to their salvation.

In the wild fishes, a population reduction occurs gradually as eyed eggs and fry, the most susceptible stages, may suffer a complete year class loss due to the increased acidity of the water from snowmelt and resultant aluminum deposition at the very time they are emerging. A year class loss may be followed by successful reproduction the following year, but with the continued acidification of the water, as the soils and bedrock buffering action is exhausted, poor or total loss of year classes increases, and only a few older fish remain. Eventually, they too disappear. This is how nearly 10,000 known lakes and hundreds of brown trout streams and 2 dozen salmon streams worldwide lost their once abundant game fish populations, and thousands more are expected to be lost within the next decade unless immediate action is taken worldwide to reverse the current rate of acidification of our fresh waters.

A random sampling of fish commission stream files of first to third order—that means small headwater—mountain trout streams which are otherwise unimpacted, indicates that a trend toward degradation does exist. Of 47 such streams for which reasonable comparisons are available, approximately two-thirds displayed an apparent downward trend in alkalinity and pH, while only 5 displayed upward trends respectively in pH and alkalinity. An alarming statistic is that the average alkalinity, the most important indicator of these streams, based on trend lines plotted from 1964 to 1980, decreased by half, from 14.6 to 7.4 ppm. Alkalinity below 10 ppm is widely regarded as being extremely low, making water vulnerable to rapid changes in pH such as occurs during heavy storms or snowmelt runoff. There are also dozens of streams which have lost or are in stages of losing wild brown trout populations. In addition, there are additional dozens where we have been forced to stop stocking the less tolerant rainbow trout or to delay any stocking in spring until after the snowmelt-caused acidity has occurred.

The utilities researchers have suggested that the solution to this dilemma might be as simple as "liming the lakes and streams," or rearing more acid-tolerant fish. These suggestions accomplish no more than establish the bias or ignorance of those who raise them. Such "solutions" are interim, limited-use, "Bandaid" techniques at best, possibly useful on selected small, high-value waters after a permanent course to solve the long-term problem has been taken, in order to save the water until the impacts of this course can correct the current trends.

While Pennsylvania is primarily an industrial and agricultural State, recreational fishing and hunting are also big business. Our State supports 40 million angler days annually, which, assessed at \$40 per fisherman day, result in a yearly evaluation of \$1.6 billion.

If 30 percent of this fishery, which is presently endangered, were lost, we would expect an annual recreational lost cost of \$200 million.

Most of the proposed research would only further prove what is already known. The National Academy of Sciences reported in September 1981 that the evidence linking acid rain to atmosphere emission of fossil fuels and metal smelters is "overwhelming." Must we have a smoking gun and a warm corpse before we take action to discourage murder?

Washing coal is cheap and is a logical first step. Japanese industry installed over 1,000 scrubbers. Why not provide incentives for our industry to devise a better, less expensive method of doing the job, and to do the job better than demanded?

Research must not be used as a substitute for action. If it is, we may look back upon the eighties and acid precipitation as the best documented, foreseeable, and predicted disaster of our time. Dying fish should tell us something about the condition of this planet we live on.

As a starting point, I highly recommend bill 1706 proposed by Senators Mitchell and Stafford for a total emission reduction. We can then evaluate the effects of this reduction, the most cost-effective segment of controls ultimately required, and determine further needs for curtailment based upon this analysis.

Thank you for this opportunity to present these issues to this committee.

[The prepared statement of Frederick W. Johnson follows:]

STATEMENT OF FREDERICK W. JOHNSON, WATER RESOURCES COORDINATOR,
PENNSYLVANIA FISH COMMISSION

Pennsylvania is not only underlain by 80 billion tons of coal, 30 billion of which is proven recoverable, but our forests, farms and streams support several of the state's most important industries. We must balance the expansion of the present extraction of 80 million tons annually—third highest in the nation—with possible damages to our farming, lumber, hunting, fishing and tourism industries.

Our state was a leading coal producer throughout most of the past two centuries, peaking at over 160 million annual tons in the 1920's. We recognize the urgent need to produce and consume coal as expeditiously and efficiently as possible, without causing further damages to our other resources and the health of our citizens. Failure to properly balance these needs in the past has resulted in the extreme degradation of over 3,000 of the state's 17,000 miles of principal streams as a result of mine acid drainage and mining sediments. Applying this ratio to the state's 45,000 total stream mileage equates to over 7,900 miles of stream and river unsuited for most uses. After over twenty years of reclamation effort, this loss has been reduced by about 30 percent—to 2,200 miles of major streams and rivers. Most of these are mountain streams, whose "opportunity lost" annual value for a typical mile of fishery is \$45,000.

Estimates for reclaiming the quarter million acres of unreclaimed strip mine land in the state so they no longer pose environmental problems range from \$5 to 15 billion; reclaiming them to usefulness for other purposes such as agriculture, industry and recreation would cost far more.

But, even as we continue the struggle to head off an increase of the type of losses which have blighted our land and waters for so long from below the surface, we now discover that the threat from above may soon cause even greater losses.

Pennsylvania, downwind of the Ohio Valley, the nation's greatest industrial complex, which indeed includes our own steel capital of Pittsburgh, receives, not surprisingly, what is probably the most acidic precipitation in the world encompassing so large an area. The EPA has predicted that, based upon existing legislation for the control of sulfur and nitrogen emissions, and predicted increase in coal consumption, the amount of those substances entering the air will increase through 1995,

even if "best available controls" are practiced. Even if it doesn't get any worse, or if emissions were to decrease somewhat, our situation is still critical.

I hope this subcommittee will listen to other authorities on the subject of acid damages to crops, forests, paint, concrete, deposition of metals, and endangerment of human health and will limit my remarks to the subject which I know best—fish—the miner's canary for our human population.

I speak both as an angler and a scientist. The former role allows me a touch of emotionalism; the latter keeps me honest.

The acidity of any lake or stream is the result of the interaction of the pH of the ultimate source, rainfall, or snow (overlooking dry deposition) and what happens to that drop of water or snowflake from the time it hits the ground until it enters the lake or stream. The alkalinity of the soils and the bedrock of the watershed have a varying capacity to buffer or neutralize the acid in the precipitation. This ability can vary greatly, even in adjacent basins. In Canada, Scandinavia, and the Adirondacks, where many lakes and streams have already been acidified in the last decade or so to the extent that they no longer support game fish, the glaciated soils are thin and the bedrock is predominately granite and quartz.

Fortunately for us in Pennsylvania, many of our valleys are underlain with limestone deposits, whose ability to buffer the deadly rain is almost infinite. However, when we leave the valleys for the rolling Appalachian mountains, the limestone gives way to shale and sandstone bedrock, and the soils become much thinner. While these offer considerably greater protection than the granites and gneisses to our north, their buffering capacity, as we are sadly discovering, is far from infinite. I like to think of it as having been given a decade or two of grace to try to save our valuable mountain resources.

It is our low order (smaller) mountain streams, those pristine gems which are the home of our prized wild brook and brown trout, which are now in the front lines of the battle being fought by utilities and industry against those whose concerns and careers are linked to their salvation.

In the wild fishes, a population reduction occurs gradually as eyed eggs and fry, the most susceptible stages, may suffer a complete year class loss due to the increased acidity of the water from snow melt and resultant aluminum deposition at the very time they are emerging. A year class loss may be followed by successful reproduction the following year, but with the continued acidification of the water, as the soils and bedrock buffering action is exhausted, poor, or total loss of year classes increases, and only a few older fish remain. Eventually, they too disappear. This is how nearly 10,000 known lakes and hundreds of brown trout streams and two dozen salmon streams worldwide lost their once abundant game fish populations, and thousands more are expected to be lost within the next decade unless immediate action is taken worldwide to reverse the current rate of acidification of our fresh waters.

A random sampling of Fish Commission stream files of first to third (that means small head water) order mountain trout streams which are otherwise unimpacted, indicates that a trend toward degradation does exist. Of 47 such streams for which reasonable comparisons are available, approximately two-thirds displayed an apparent downward trend in alkalinity and pH, while only 5 displayed upward trends respectively in pH and alkalinity. An alarming statistic is that the average alkalinity, the most important indicator of these streams, based on trend lines plotted from 1964 to 1980, decreased by half, from 14.6 to 7.4 ppm. Alkalinity below 10 ppm is widely regarded as being extremely low, making water vulnerable to rapid changes in pH such as occurs during heavy storms or snowmelt runoff. Also there are dozens of streams which have lost or are in stages of losing wild brown trout populations. In addition, there are additional dozens where we have been forced to stop stocking the less tolerant rainbow trout or to delay any stocking in spring until after the snowmelt-caused acidity has occurred.

The utilities researchers have suggested that the solution to this dilemma might be as simple as "liming the lakes and streams", or rearing more acid tolerant fish. These suggestions accomplish no more than establish the bias or ignorance of those who raise them. Such "solutions" are interim, limited-use, "bandaid" techniques at best, possibly useful on selected small, high value waters after a permanent course to solve the long term problem has been taken, in order to save the water until the impacts of this course can correct the current trends.

While Pennsylvania is primarily an industrial and agricultural state, recreational fishing and hunting are also big business. Our state supports 40 million angler days annually, which, assessed at \$40 per fishermen day,¹ result in a yearly expenditure

¹ Based upon travel costs and consumer surplus technique, taken from the 1981 Water Resources Council Reference Handbook.

of \$1.6 billion. According to our surveys, over 35 percent of this effort is directed to our trout fishery. If 30 percent of this fishery, which is presently endangered, were lost, we would expect an annual recreational loss of \$168 million.

Most of the proposed research would only further prove what is already known. The National Academy of Science reported in September 1981 that the evidence linking acid rain to atmosphere emission of fossil fuels and metal smelters is "overwhelming". Must we have a smoking gun and a warm corpse before we take action to discourage murder?

Washing coal is cheap, and is a logical first step. Japanese industry installed over 1000 scrubbers. Why not provide incentives for our industry to devise a better, less expensive method of doing the job, and to do the job better than demanded?

Research must not be used as a substitute for action. If it is, we may look back upon the 80's and acid precipitation as the best documented, foreseeable, and predicted disaster of our time. Dying fish should tell us something about the condition of this planet we live on.

As a starting point, I highly recommend Bill #1706 proposed by Senators' Mitchell and Stafford for a total emission reduction. We can then evaluate the effects of this reduction, the most cost effective segment of controls ultimately required, and determine further needs for curtailment based upon this analysis.

Mr. ERTEL. Thank you very much, Mr. Johnson, for your testimony on the impact of acid rain and the burning of coal on the State of Pennsylvania. Certainly that is illustrative of other areas of the country as well.

I might turn to Dr. Wilbanks. Your testimony, I noted, seemed to deal directly with the domestic utilization of coal, and you did not really speak of the exportation of coal. Is there a market for coal in the export markets, and how does that impact on your statement?

Dr. WILBANKS. At one point in the written testimony, a part of it that I did not repeat in my remarks here, I mentioned that there appears to be a little bit of evidence that the domestic use of coal is decoupling somewhat from the domestic production of coal. Our rate of production rose faster between 1978 and 1980 than our rate of domestic use of coal, and the main explanation for that is coal exports. This suggests that we can proceed with plans to develop our domestic coal resources without having to resolve all the uncertainties about the domestic use of coal at this point, because it is likely that if the domestic coal we develop and produce is not in demand within the country it can find a market outside.

Mr. ERTEL. We still have problems with the production and transportation of that coal to the export ports. The only uncertainty that remains in the export markets is what happens when we burn it, the direct combustion. That is the only uncertainty that is left, is it not?

Dr. WILBANKS. There are several uncertainties connected with the export markets. One is port capacity, there as well as here, and how it affects what we can do to increase our exports. Another has to do with demands on transportation facilities here, especially congestion in towns and cities that the rail routes pass through. And a larger issue is impacts on the world environment of the combustion of coal wherever it takes place, whether it is in this country or elsewhere. Certainly issues such as CO₂ and to some degree acid rain are global issues, not just national issues.

Mr. ERTEL. They seem to be being resolved at least in world opinion with the utilization of coal if our export markets are increasing, or else they are just ignoring the problem.

Dr. WILBANKS. Not only in regions such as Europe but in Southeast Asia and other regions as well, countries are looking to coal as

the main substitute for oil as it gets more expensive and scarce, and they are very interested in exports of coal from the United States. A director of the Asian Bank several weeks ago suggested the desirability of a Public Law 480 type program in the United States for coal, offering concessionary agreements with foreign countries to purchase American coal using currencies of their own countries in order both to meet their energy needs and to encourage coal production in the United States. That is an example of an interest in other parts of the world in what we do with coal production.

Mr. ERTEL. You have indicated in your analysis a couple of reasons. You talk about the expansion market in the United States and the replacement market. I think you are saying that we have failed to encourage the replacement of oil and gas or at least are moving away from conversion from oil and gas consumption to coal consumption. Is that what you are saying about the direction our governmental policy is taking at this time?

Dr. WILBANKS. Attempts to develop effective policies to encourage that kind of conversion are recent enough that it is hard to tell exactly how successful various kinds of approaches might be, but it is quite clear that there are a great many cases around the country where the use of coal in place of oil appears to make economic sense, appears to make sense for improving our vulnerability situation related to oil imports, makes sense for lots of reasons—but it is not happening. I tried to summarize some of the reasons why this is not happening right now. That does not necessarily mean that it will not happen during the 1980's. One factor has been uncertainty about government policy, what kinds of incentives or mandates are going to be established by the Federal Government and as a result what the conditions are going to be for those decisions.

Mr. ERTEL. I have a copy of a memo that was sent around to the members of the Science and Technology Committee on the proposed budget for fossil energy, research and development. I thought I might give you a couple of figures and see what you thought of that in relationship to your testimony today and the uncertainties and also where Government policy is going.

In 1981 we appropriated \$993 million for fossil energy development. Fiscal year 1982, conference figures were \$431 million, a little less than half of what we did in 1981. Fiscal 1983, the original request from DOE was forecasted at \$366 million. Their amended request was \$305 million, and what OMB approved was \$106 million. We are at approximately 10 percent of the effort, at least just in numbers, by fiscal year 1983 as we were in fiscal year 1981. My understanding is that the figure in fiscal year 1983 is for contract closeout costs. In other words, we will be down to a fossil energy development effort to solve some of the problems you have elicited and that Mr. Johnson has talked about at basically a zero figure. What is your view of that kind of a governmental policy if we are going to develop coal as an alternative? And if you approve of that policy, who do you suggest is going to solve the problems that have been elicited here today?

Dr. WILBANKS. Sir, my personal opinion is that the trend in support and Federal involvement in coal research policymaking and the 1983 proposed funding level are both out of line with national

needs. Let me just mention a few things that I think are worth considering—

Mr. ERTEL. Did you say they are—

Dr. WILBANKS. Out of line with national needs.

Mr. ERTEL. OK.

Dr. WILBANKS. I think there are several things that need to be considered seriously, and they add up to a larger budget figure than that 1983 one. One thing that would do a lot to help encourage the use of coal in the United States is economic recovery; I think especially actions that bring the interest rate down are going to help coal as a capital-intensive option. Bringing the interest rate down might have more of an effect than natural gas price decontrol, for example. A second need is to reduce uncertainties about future electricity demand and especially supplies and prices of natural gas in the United States. That involves research on potentials and forecasting of gas supply and energy conservation: what we can expect from those options. A third thing that I think worth considering is Federal assistance with the capital supply that utilities and industrial firms must have to switch from oil to coal, where it is clear to them that it makes sense. Capital constraints are a problem for firms and utilities that are financially strapped right now.

There are also some R. & D. categories that are important. One is environmental and health research. This includes research on effects, reducing uncertainties about effects, providing reliable and credible information about effects. It includes the development of improved environmental controls, development and testing, and it includes a program of monitoring, so that there is independent information about what is happening. Then I think there are technology R. & D. needs related to the ways we can use coal. One is technology R. & D. to reduce the cost of coal use, especially to reduce the capital costs and to reduce the inconveniences associated with materials handling and waste disposal. We need to continue the R. & D. activities that are already going on which are intended to make coal more attractive as an energy option for small users. This involves technology development and improvement of the sorts happening now in areas such as fluidized bed coal combustion and coal-water mixtures. I think it also includes demonstration programs.

I fear that saying that everything that is going on is either (a) commercial activity that we can leave to the market or (b) long-term, high-risk activity leaves a gap in the middle where there are some options that are close to being ready for market use but which may not cross that boundary without help. One example could be fluidized bed combustion. A cost-shared demonstration program that has the effect of building up enough experience so that a manufacturer can build and sell a more or less standard unit with a guarantee would do a lot to move this option into the marketplace during the 1980's, when we are going to have to be making decisions about a lot of capital stock replacement. So I think there are needs for a substantial continuing role on the part of the Federal Government in coal research and development and policymaking, and I do think that those funding levels are too low to make that possible.

Mr. ERTEL. Thank you, Dr. Wilbanks.

Mr. Johnson, you have heard some of Dr. Wilbanks' testimony about what I think is the need to utilize more coal in the future. That raises the problems that you discussed here with acid rain and a lot of problems with combustion. How do you propose that we would solve those problems so that the trout streams, if you will, and I am a trout fisherman—do not catch many, but I try, either because they are not there or because they do not get on my hook—but how do you suggest that we solve the problems that he is posing? If we solve those problems, how do we solve the problems that you have raised as far as the environment is concerned?

Mr. JOHNSON. Congressman, I am not going to give you specific solutions, because I am not a scientist, certainly not a chemical scientist. But the coal industry tells me that they can remove about 98 percent of the sulfur from the coal, but it costs money. I believe that Japan has proven that it is possible to use even the techniques that are available today and still have a pretty good economy. But I suggested that what we do is provide the right type of tax incentives for the industry to come up with better, more cost-efficient solutions, and that is one of the reasons why I like the Mitchell bill, which starts out by simply saying we are going to have to reduce it by a certain amount. Now, that amount is not the total reduction that is going to be required, and perhaps to my economist friend here, that may leave a certain amount of uncertainty, because it does not tell the utility companies just how much they are going to have to reduce it at a later stage. But I believe that the reduction proposed can be obtained with inexpensive techniques. It is not a difficult reduction. It may seem that in some areas, but overall it is not too bad, especially if some tradeoff is allowed for the reduction.

When you get beyond that, then we are going to have to give them the incentives for the next stage, which is the additional reduction, that hopefully we will then be able to pin down what is required. I do not believe it is empirically possible to pin down the exact amount of reduction needed to save that trout stream you like to fish, because we do not really know, nor does anyone profess to know how much a 50-percent reduction in sulfur is going to reduce the acidity of rainfall. We are going to have to take a look at a reduction and move to the next step.

Mr. ERTEL. Do you not create the real problem that Dr. Wilbanks talked about or continue it, the uncertainty? There is going to be an uncertainty on the industry to use the combustion of coal, because the next year we will put a new requirement on them, increasing the capital costs in a climate that is uncertain to start with. How do we resolve the problem Dr. Wilbanks gives of the uncertainties? Are they irreconcilable? Do we say that we have an irreconcilable conflict and make the option that we burn coal and to heck with the environment, or we are going to be purely environmentalists and not burn coal? Is there some way in the middle to solve both problems which would be a reasonable position for those—in this case we are talking about acidic rain, but there are other effluents to worry about as well.

Mr. JOHNSON. You might sell them more Pennsylvania coal. That is cleaner. That would be my first suggestion, of course. And if they want to use the

Mr. ERTEL. You also sell a lot more of anthracite, which is even cleaner.

Mr. JOHNSON. If they want to use the Ohio and Indiana coal they will have to clean it up more, but as I indicated, I believe the first stages of cleaning, and even Governor Brown has agreed to that, washing the coal is not an expensive stage. Dr. Heinz Pfeifer of P.P. & L. tells me that he would like to see everyone wash their coal, and I believe perhaps just washing the coal would meet the first stage, and then we should be in a position where we can make a better analysis of what is happening as a result of X amount of reduction of sulfur.

Mr. ERTEL. I am told we have an expert on coal washing on the next panel, so we will defer the coal-washing until that testimony. Congressman Skeen.

Mr. SKEEN. Thank you, Mr. Chairman. I am sorry I was late. I did read the testimony of Dr. Wilbanks. It is very illuminating, and I think it is an objective view, an overall view of what the total problem is. I think we are reduced now to talking about the unknown area of the variables involved in how we quantify parameters, how we set standards. This has been a problem that we met when we approached the problems of the Clean Air Act and all the other provisions that we have become environmentally sensitive to in the last 10 or 15 years. I am very curious, I would like very much to listen to this coal-washing proposition. I want to know what it does to water, what the proposals are, what the costs are and so on. You mentioned that the industry has said that they can remove 98 percent of the sulfur. Do they consider that as economically feasible?

Mr. JOHNSON. No, sir.

Mr. SKEEN. At what point do they consider that an economic optimum?

Mr. JOHNSON. I believe, with all due respect, sir, that question should be addressed to the next panel.

Mr. SKEEN. I will be happy to do that. I wondered if anyone had ever expressed this to you in any way and quantified this.

Mr. JOHNSON. No, they have not. There is a certain amount of research going on now with other techniques such as a product called Sulfex, techniques where you can remove the sulfur and use it for other products, which I am optimistic enough to believe that someday the removal may cost nothing. At one time I believe one of the problems with water, was removal of mercury from some of the film products, and they found finally that when forced to look at it closely that they could not only remove it, but they could make money while doing so.

Mr. SKEEN. From the byproduct?

Mr. JOHNSON. Yes.

Mr. SKEEN. I will leave you with the idea since we are all being proud of our local products, we in New Mexico have a low-sulfur coal. We have been approached to ship it to the East. I do not think that is the real problem. I would like to inject this idea into this discussion, though, for my trout fisherman friend over here in the Congress. Given the problem that we had with alkalines in the southwestern part of the United States, we developed alkaline-resistant strains of alfalfa. You might do that with the trout.

Mr. JOHNSON. That has been attempted.

Mr. SKEEN. Thank you, Mr. Chairman.

Mr. ERTEL. Thank you, Mr. Skeen.

One question that has bugged me to some degree, and I keep hearing it from experts, is the removal of the impurities. They always talk about percentage reductions. They talk about 98-percent reduction. I wonder if we have not really framed the question in the wrong way. When we talk about a 90-percent reduction, depending on how much sulfur you have in that coal, the absolute amount of sulfur going into the atmosphere even with the best technology may be much higher than if we start with a lower-sulfur coal with a 50-percent reduction, yet the legislation reads, the amount of reduction, 90 percent of 7-percent coal, multiply that, you have got about seven-tenths of a percent left in the coal, but if you would start with a 1.3-percent sulfur content with a 50-percent you are right at the same point. Why do people in your profession raise the question in that way? And is it a valid or useful way of phrasing it?

Mr. JOHNSON. No, I would agree with you. I believe that what we are doing is parroting the coal industry.

Mr. ERTEL. I was reminded by a staff person that the Congress phrased it that way, but I assume we got that from you all. We are not creators of thought. We are followers. I think sometime we ought to change our frame of reference.

Dr. WILBANKS. I agree with you, sir. The point is the emissions from the facility, not the percentage of potential pollutants removed. But I think most of the scientists at Oak Ridge have the feeling that the decision was related more to political considerations than scientific ones.

Mr. ERTEL. With that, I thank you very much for your testimony, and I appreciate very much your help in looking at this issue. It has been very helpful. Again, thank you very much.

The subcommittee will stand in recess for approximately 10 minutes. We have a vote on the floor.

[Recess].

Mr. ERTEL. The subcommittee will come to order. I would like to apologize to you, gentlemen. We had a series of votes, a couple, actually, in the interim and it didn't make sense to come back for 5 minutes and then have to go back over, so we all remained.

Our next witnesses are Mr. H. Kerner Smith, manager of the Fossil Power Generation Division, Babcock and Wilcox Co., Mr. Tobias Anthony with Research-Cottrell, Inc., and Mr. Kurt Yeager, director, Coal Combustion Systems Division, Electric Power Research Institute.

Gentlemen, we appreciate your coming to give us your thoughts. I recognize Mr. Kerner Smith.

[The biographical sketch of Mr. Smith follows:]

H. KERNER SMITH

H. Kerner Smith is manager of Marketing for the Fossil Power Generation Division of Babcock and Wilcox, a unit of McDermott, Incorporated. The Division provides complete fossil steam systems in the United States and throughout the world.

Mr. Smith was born and raised in Pennsylvania and graduated from the U.S. Merchant Marine Academy in 1966 with a B.S. in Marine Engineering. After serving in the Merchant Marine, he joined Babcock and Wilcox and has held positions

in Engineering, Project Management, Sales and Marketing. He holds an M.B.A. degree from Boston University and is a member of Phi Beta Sigma, and the American Society of Mechanical Engineers.

STATEMENTS OF H. KERNER SMITH, MANAGER, FOSSIL POWER GENERATION DIVISION, BABCOCK & WILCOX CO.; TOBIAS ANTHONY, RESEARCH-COTTRELL, INC.; AND KURT YEAGER, DIRECTOR, COAL COMBUSTION SYSTEMS DIVISION, ELECTRIC POWER RESEARCH INSTITUTE

Mr. SMITH. Thank you, Mr. Chairman.

Mr. Chairman and distinguished members of the subcommittee, it is my pleasure to have the opportunity to discuss with you today the current state of development, the promise and the problems remaining to be solved prior to the full commercialization of fluidized bed coal combustion, which is a developing technology that will permit the use of coal in an environmentally acceptable manner.

Babcock and Wilcox has provided leadership in applications of steam generation since 1867. Our boilers powered Thomas Edison's lab, and most of our country's naval and merchant vessels. The company is the leading supplier of coal-fired steam systems to electric utilities and industrial users of steam. B. & W. has been known as a pioneer in fossil steam systems and supplies complete systems, including fuel preparation and air pollution control systems as shown in exhibit 1, a 400 MW station in Texas.

For your convenience, I have given you a copy of those exhibits in hard copy. Some current significant commercialization efforts being made to promote the use of coal include the development of advanced pulverized coal-fired boilers, high solids coal-water slurries, wet and dry SO₂ scrubber development and atmospheric fluidized bed boiler development, the subject of this testimony.

Although fluidized bed applications in the process field have been in place for many years, little technological development of their use for combustion of coal occurred. About 5 years ago, we recognized the potential benefit of generating clean power from coal without the use of SO₂ scrubbers utilizing fluidized bed technology.

In fluidized bed combustion, coal is burned as it is suspended in a bed of limestone. The calcium in the limestone absorbs the sulphur liberated from the coal and the product of this reaction and the ash are removed from the bottom of the bed and discharged for disposal and potential use as a landfill or construction material. This prevents most of the sulphur from polluting the atmosphere.

In 1976, Babcock and Wilcox began devoting substantial resources to this program. This began with self-funded development and later contract research programs with the Electric Power Research Institute, the Tennessee Valley Authority, and the Department of Energy.

The two major programs are the EPRI/B. & W. test unit at our Alliance Research Center—the most sophisticated fluidized bed facility in existence, and the B. & W./TVA 20 MW pilot program for which B. & W. is supplying a turnkey fluidized bed boiler island consisting of boiler and emission control equipment as shown in exhibit 2.

Our research expenditures for fluidized bed combustion are shown in the third exhibit. The company will spend over \$25 million of its own funds to develop this technology. Of course there are substantial contributions from EPRI and TVA. This is the largest project under development by Babcock and Wilcox at this time, and the most significant in terms of company contribution of resources and capital.

An overview of the commercialization timetable for atmospheric fluidized bed boilers is shown in exhibit 4. This is indicative of our position that it is necessary to have a demonstration plant prior to full scale offerings to and acceptance by the utility industry. The exhibit also indicates that the large pilot being designed and built for TVA will provide the necessary experience to serve as a demonstration plant for reliable industrial size plants as well.

The past efforts and the important continued participation of EPRI, representing the potential users of this technology, parallels the completion and operation of the B. & W./TVA 20 megawatt pilot plant in May of 1982. These efforts must lead to a decision to progress with the final design of a demonstration plant by late 1983 if such a plant is to be on-line in 1987 or 1988. TVA has funded preliminary design of this 200 megawatt plant and the Babcock and Wilcox boiler design is shown in exhibit 6. This program is vulnerable should funding for the demonstration plant not be available, since it is doubtful that the private sector could support the program because of the current financial conditions of the electric utilities.

Now, I will direct my discussion toward the promise of atmospheric fluidized bed combustion (AFBC) boilers. Our view of the market potential is that AFBC boilers may compete with pulverized coal-fired boilers equipped with SO₂ scrubbers firing high sulphur bituminous coals in the late 1980's.

AFBC boilers firing severe slagging and low rank coals appear to offer further economic advantages versus their pulverized coal equivalents.

Recent studies funded by EPRI comparing AFBC boilers to conventional boilers with scrubbers indicate a 10- to 15-percent overall savings in generating costs for typical eastern bituminous and western sub-bituminous coals. A comparison of boiler size for these typical coals is shown in exhibit 7. However, coal rank affects the size of conventional pulverized coal boilers. Exhibit 8 compares the pulverized coal design of the previous exhibit to designs for Texas and Northern Plains lignites. With conventional firing, temperatures are high enough to form slag which is detrimental to boiler performance. Progressively larger furnaces are required on these fuels as coal rank decreases.

In contrast to this characteristic of conventional boilers, AFBC boilers burn the fuel at temperatures below the point where slag can form so that there is no requirement for bigger AFBC boilers as the slagging tendency becomes greater. This lower combustion temperature limits formation of NO_x and is a further benefit.

When we compare a conventional boiler designed for severe slagging low rank coal to an AFBC design for the same coal (exhibit 9), we find that the AFBC boiler is considerably smaller than the conventional pulverized coal boiler. This may be significant because of

the future use of low rank and often low sulphur coals which often cost less per unit of heating value, and are abundant in our country.

Our appraisal of the market potential for AFBC boilers is shown on exhibit 10. The current market for new coal-fired boilers is less than half of the historic average. Our forecasts indicate a potential market of 17,500 MW in 1990 and a market of about 1,400 MW for AFBC boilers. A potential market for retrofit of AFBC boilers to convert existing boilers may develop if economics favor AFBC.

Now, let us address some of the problems facing this technology. If everything pointed to the conclusion that fluid bed combustion was economical and technically feasible, it still would be faced with competing with a well-established and proven existing alternative—the pulverized coal-fired boiler with scrubber. This illustrates why it is necessary to continue Government and industry support of this development to demonstrate to the user that performance, reliability, cost, and business risks associated with the firsts-of-a-kind are worth the rewards of potentially lower generating costs and displacement of oil and gas as utility fuels.

Reliability of equipment is of prime importance today because of high fuel costs for replacement power and availability targets which can affect utilities' rates of return if not met. There are no fluid bed boilers in operation at utility steam conditions. Even for industrial conditions, none has demonstrated long-term performance, operating reliably day in and day out for extended months. None offers proof of continuous high combustion efficiencies and sulfur captures equal to mature utility size pulverized coal units with scrubbers. Builders of new electric generating facilities also look to equipment which can be delivered and erected within assured schedules.

The existing program elements support answers to the problems I have mentioned, and from the technological standpoint, the program is progressing well toward providing timely answers to these problems. The issues of long-term operation, reliability, and emissions control in a real utility environment with various fuels and bed materials should be answered by the B. & W./TVA pilot beginning next May. Investigation of problems of the effects of wide fuel ranges, screening studies of materials and other extensions to the technology base should be continued on the EPRI/B. & W. facility at our Alliance Research Center to provide more assurance of program success.

The remaining problems—those of scale up to full commercial utility size, demonstration of operability, and reliable, lower bus bar generating cost must be answered by the construction of a demonstration plant to operate by 1988. Exhibit 11 represents the Babcock & Wilcox design for this facility.

Finally, our own substantial commitment to this technology, both resourcewise and financially, is expected to provide a return to the company in the early 1990's in supplying competitive, reliable atmospheric fluidized bed boilers and fulfilling our parent McDermott's slogan, "No matter how the world solves its energy problems, McDermott is involved."

That completes my prepared testimony. Thank you very much.
[The prepared statement of H. Kerner Smith follows:]

PREPARED STATEMENT OF H. KERNER SMITH, BARCOCK & WILCOX, UNIT OF
McDERMOTT, INC.

FLUIDIZED BED BOILERS—PROMISE AND PROBLEMS

Mr. Chairman and distinguished members of the Subcommittee, I am Kerner Smith, Manager of Marketing for the Fossil Power Generation Division of Babcock and Wilcox. It is my pleasure to have the opportunity to discuss with you the current state of development, the promise, and the problems remaining to be solved prior to the full commercialization of fluidized bed coal combustion, which is a developing technology that will permit the use of coal in an environmentally acceptable manner.

Babcock and Wilcox has provided leadership in applications of steam generation since 1867. Our boilers powered Thomas Edison's lab; and most of our Country's naval and merchant vessels. The Company is the leading supplier of coal-fired steam systems to electric utilities and industrial users of steam. B&W has been known as a pioneer in fossil steam systems and supplies complete systems including fuel preparation and air pollution control systems as shown in Exhibit 1, a 400 MW station in Texas. Some current significant commercialization efforts being made to promote the use of coal include the development of advanced pulverized coal-fired boilers, high solids coal-water slurries, wet and dry SO₂ scrubber development and atmospheric fluidized bed boiler development, the subject of this testimony.

Although fluidized bed applications in the process field have been in place for many years, little technological development of their use for combustion of coal occurred. About five years ago, we recognized the potential benefit of generating clean power from coal without the use of SO₂ scrubbers.

In fluidized bed combustion, coal is burned as it is suspended in a bed of limestone. The calcium in the limestone absorbs the sulphur liberated from the coal and the product of this reaction and the ash are removed from the bottom of the bed and discharged for disposal and potential use as a landfill or construction material. This prevents most of the sulphur from polluting the atmosphere.

In 1976, Babcock and Wilcox began devoting substantial resources to this program. This began with self-funded development and later contract research programs with the Electric Power Research Institute, the Tennessee Valley Authority and the Department of Energy.

The two major programs are the EPRI/B&W test unit at our Alliance Research Center—the most sophisticated fluidized bed facility in existence, and the B&W/T.V.A. 20 MW pilot program for which B&W is supplying a turnkey fluidized bed boiler island consisting of boiler and emission control equipment as shown in Exhibit 2.

Our research expenditures for fluidized bed combustion are shown in the third exhibit. The Company will spend over \$25 million of its own funds to develop this technology. This is the largest project under development by Babcock and Wilcox at this time, and the most significant in terms of company contribution of resources and capital.

An overview of the commercialization timetable for atmospheric fluidized bed boilers is shown in Exhibit 4. This is indicative of our position that it is necessary to have a demonstration plant prior to full scale offerings to and acceptance by the utility industry. The exhibit also indicates that the large pilot being designed and built for T.V.A. will provide the necessary experience to serve as a demonstration plant for reliable industrial size plants as well.

The past efforts and the important continued participation of EPRI, representing the potential users of this technology, parallels the completion and operation of the B&W/T.V.A. 20 megawatt pilot plant in May of 1982. These efforts must lead to a decision to progress with the final design of a demonstration plant by late 1983 if such a plant is to be on-line in 1987 or 1988. T.V.A. has funded preliminary design of this 200 megawatt plant and the Babcock and Wilcox boiler design is shown in Exhibit 6. This program is vulnerable should funding for the demonstration plant not be available, since it is doubtful that the private sector could support the program because of the current financial conditions of the electric utilities.

Now I will direct my discussion toward the promise of Atmospheric Fluidized Bed Combustion (AFBC) boilers. Our view of the market potential is:

That AFBC boilers may compete with pulverized coal-fired boilers equipped with SO₂ scrubbers firing high sulphur bituminous coals in the late 1980's.

AFBC boilers firing severe slagging and low rank coals appear to offer further economic advantages versus their coal equivalents.

Recent studies funded by EPRI comparing AFBC boilers to conventional boilers with scrubbers indicate a 10-15 percent overall savings in generating costs for typical eastern bituminous and western sub-bituminous coals. A comparison of boiler size for these typical coals is shown in Exhibit 7. However, coal rank affects the size of conventional coal boilers. Exhibit 8 compares the pulverized coal design of the previous exhibit to designs for Texas and Northern Plains lignites. With conventional firing, temperatures are high enough to form slag which is detrimental to boiler performance. Progressively larger furnaces are required on these fuels as coal rank decreases.

In contrast to this characteristic of conventional boilers, AFBC boilers burn the fuel at temperatures below the point where slag can form so that there is no requirement for bigger AFBC boilers as the slagging tendency becomes greater. This lower combustion temperature formation of NO_x equals a further benefit.

When we compare a conventional boiler designed for severe slagging low rank coal to an AFBC design for the same coal (Exhibit 9), we find that the AFBC boiler is considerably smaller than the conventional pulverized coal boiler. This may be significant because of the future use of low rank and often low sulphur coals which often cost less per unit of heating value, and are abundant in our Country.

Our appraisal of the market potential for AFBC boilers is shown on Exhibit 10. The current market for new coal-fired boilers is less than half of the historic average. Our forecasts indicate a potential market of 17,500 MW in 1990 and a market of about 1400 MW for AFBC boilers. A potential market for retrofit of AFBC boilers to convert existing boilers may develop if economics favor AFBC.

Now let us address some of the problems facing this technology. If everything pointed to the conclusion that fluid bed combustion was economical and technically feasible, it still would be faced with competing with a well-established and proven existing alternative—the pulverized coal-fired boiler with scrubber. This illustrates why it is necessary to continue government and industry support of this development to demonstrate to the user that performance, reliability, cost and business risks associated with the first-of-a-kind are worth the rewards of potentially lower generating costs and displacement of oil and gas as utility fuels.

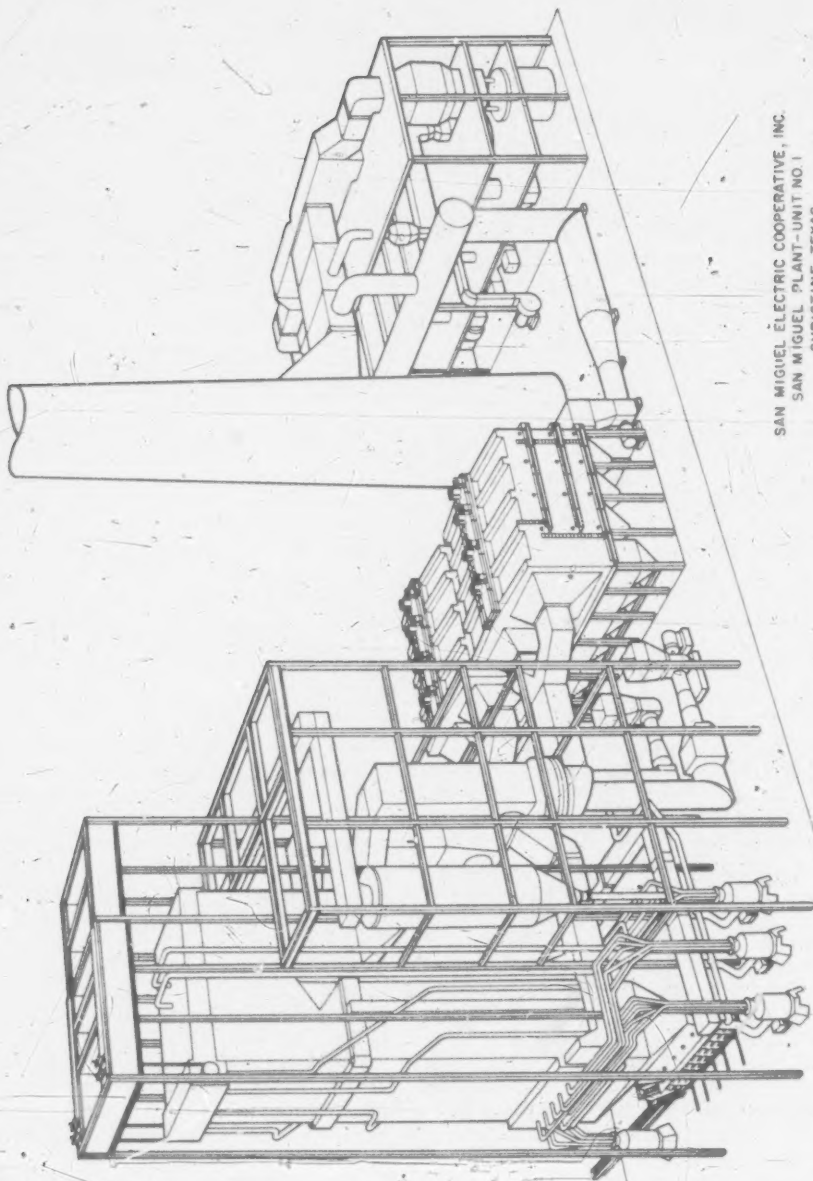
Reliability of equipment is of prime importance today because of high fuel costs for replacement power and availability targets which can affect utilities' rates of return if not met. There are no fluid bed boilers in operation at utility steam conditions. Even for industrial conditions, none have demonstrated long term performance, operating reliably day in and day out for extended months. None offer proof of continuous high combustion efficiencies and sulphur captures equal to mature utility size pulverized coal units with scrubbers. Builders of new electric generating facilities also look to equipment which can be delivered and erected within assured schedules.

The existing program elements support answers to the problems I have mentioned, and from the technological standpoint, the program is progressing well toward providing timely answers to these problems. The issues of long term operation, reliability and emissions control in a real utility environment with various fuels and bed materials should be answered by the B&W/T.V.A. pilot beginning next May. Investigation of problems of the effects of wide fuel ranges, screening studies of materials and other extensions to the technology base should be continued on the EPRI/B&W facility at our Alliance Research Center to provide more assurance of program success.

The remaining problems—those of scale up to full commercial utility size, demonstration of operability, and reliable, lower bus bar generating cost must be answered by the construction of a demonstration plant to operate by 1988. Exhibit 11 represents the Babcock and Wilcox design for this facility.

Finally, our own substantial commitment to this technology, both resource-wise and financially, is expected to provide a return to the Company in the early 1990's in supplying competitive, reliable atmospheric fluidized bed boilers and fulfilling our parent McDermott's slogan, "No matter how the world solves its energy problems, McDermott is involved."

That completes my prepared testimony.

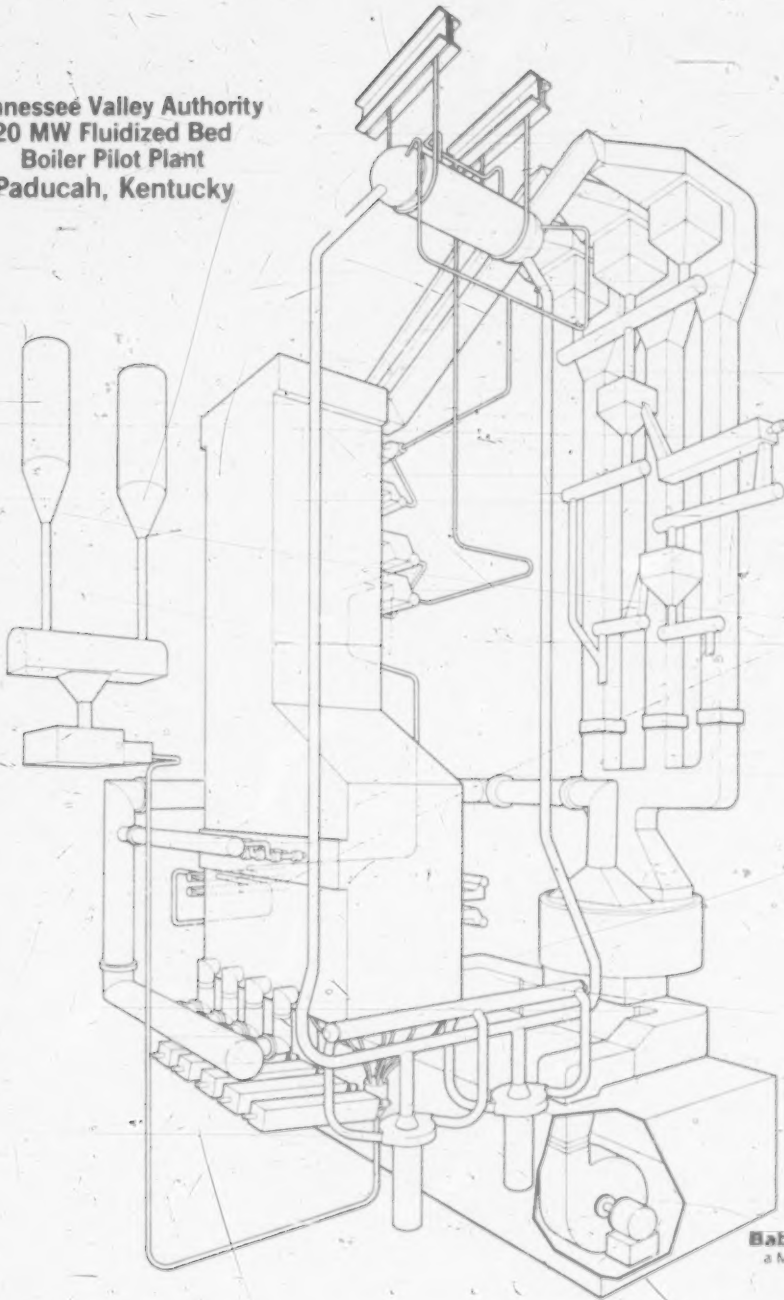


SAN MIGUEL ELECTRIC COOPERATIVE, INC.
SAN MIGUEL PLANT—UNIT NO. 1
CHRISTINE, TEXAS

Balcock & Wilcox
a McDermott company

Exhibit 1

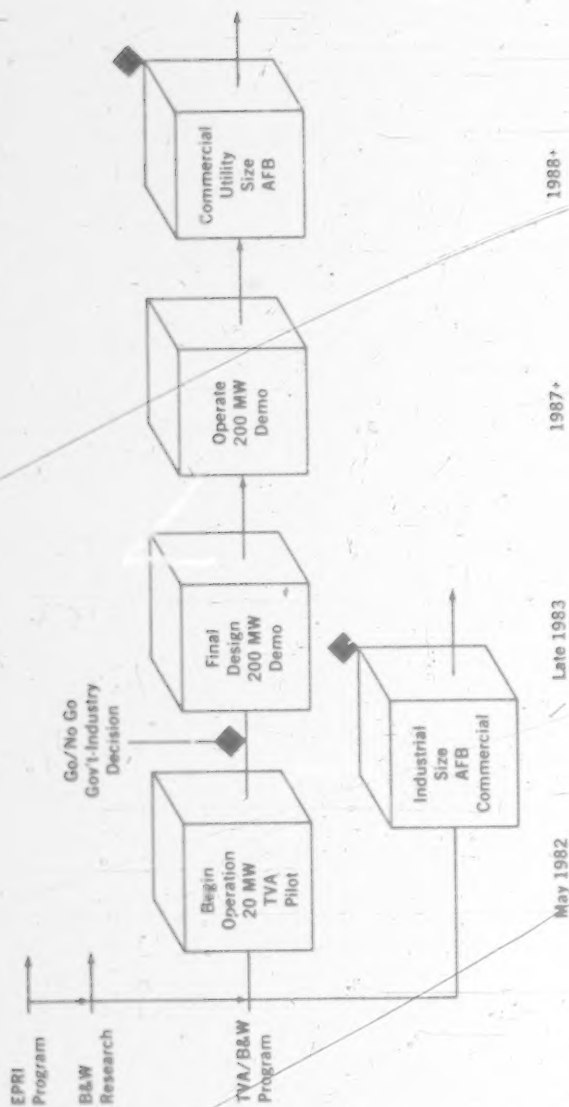
**Tennessee Valley Authority
20 MW Fluidized Bed
Boiler Pilot Plant
Paducah, Kentucky**



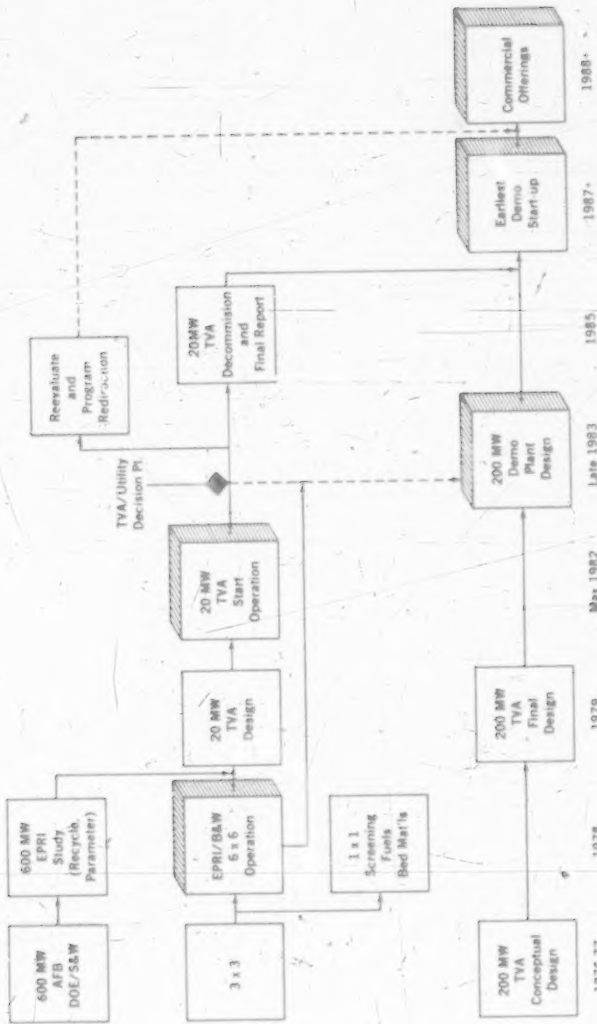
Babcock & Wilcox
a McDermott company
Exhibit 2



**Babcock & Wilcox Research Expenditures
on Fluidized Bed Combustion**

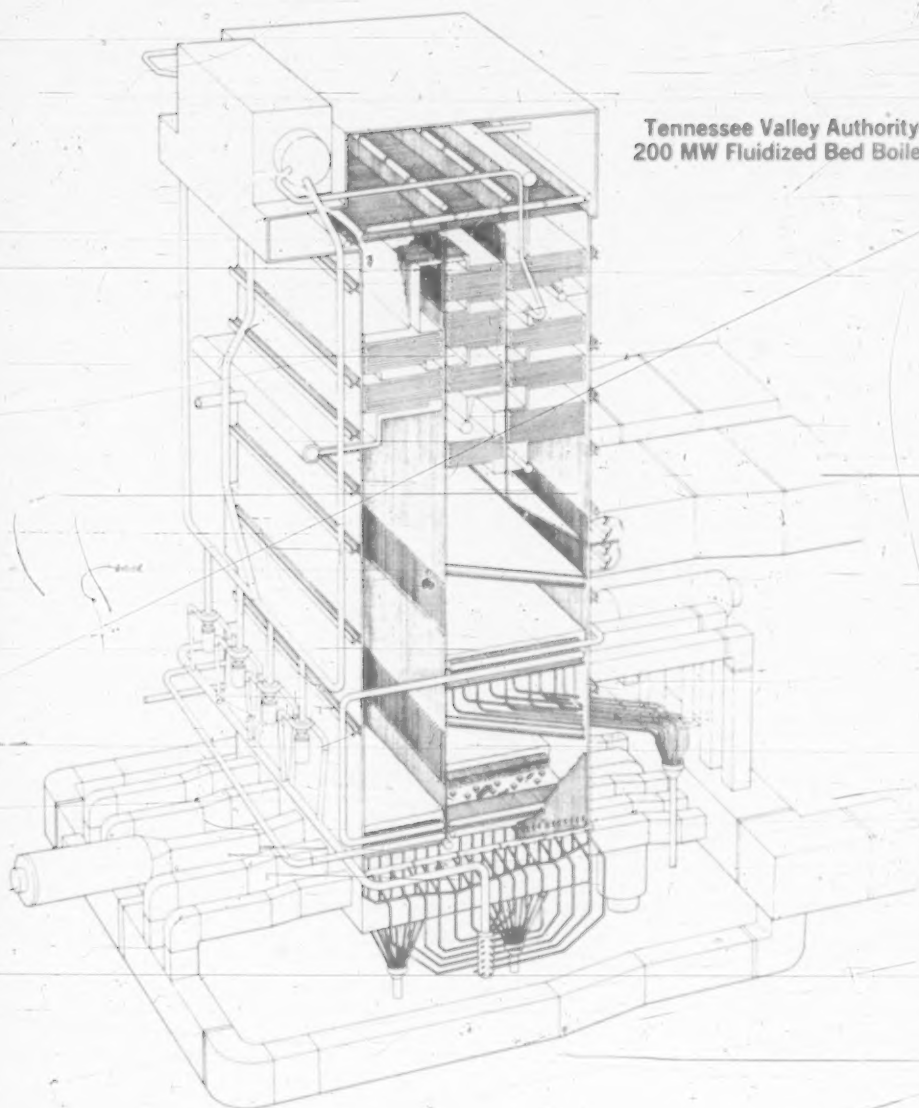


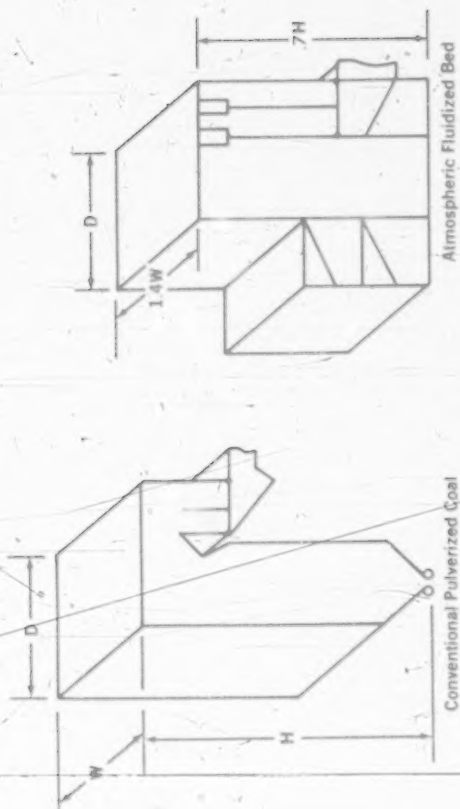
B&W Commercialization Time Table
Atmospheric Fluid Bed Boilers



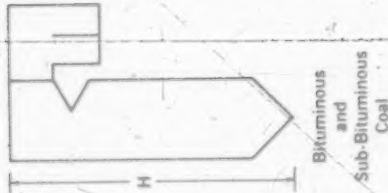
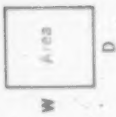
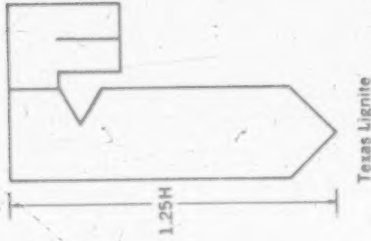
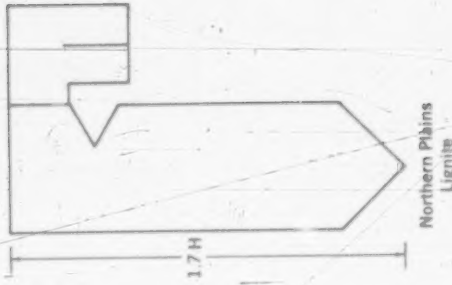
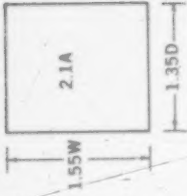
B&W Atmospheric Fluid Bed Program - Utility Size

Tennessee Valley Authority
200 MW Fluidized Bed Boiler





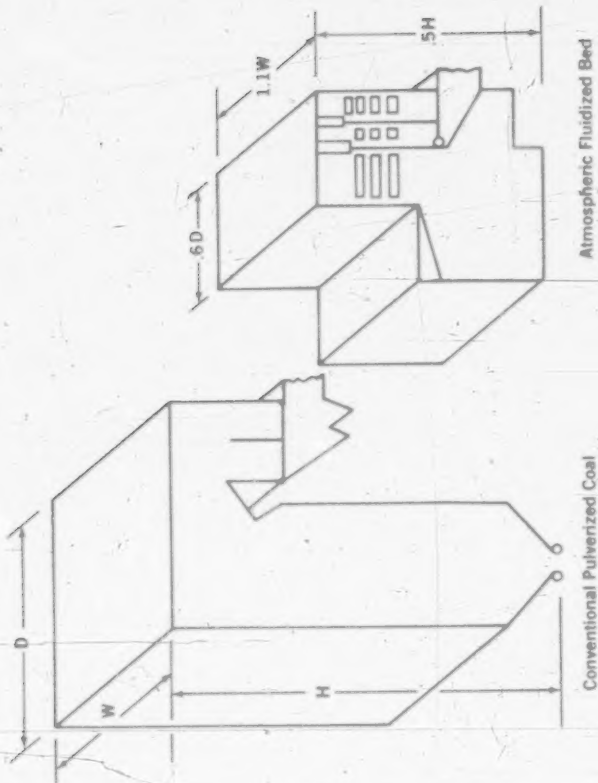
Comparison of Boiler Size For
Typical Utility Coal Specification



Source — B&W Utility Boiler
Data Base

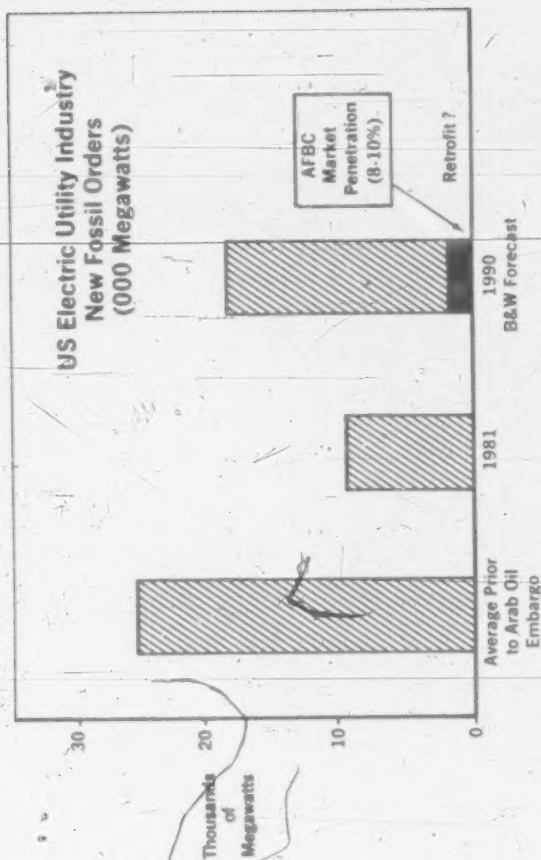
Babcock & Wilcox
a McDermott company
Exhibit 8

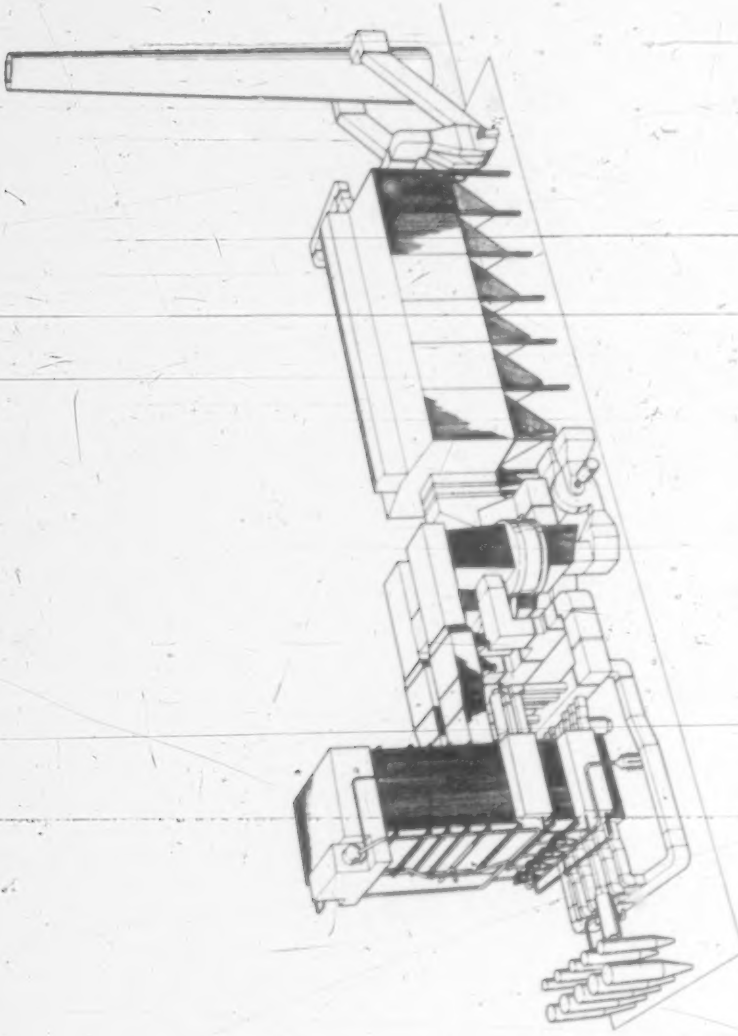
Effect of Fuel Source on Boiler Size Pulverized Coal Firing



Comparison of Boiler Size for Low Rank Fuels

Scenario Based on 200 MW Demo in 1988





**Tennessee Valley Authority
200 MW Demonstration Plant**

Babcock & Wilcox
a McDermott company
Exhibit 11

Conclusions

Basic technology questions answered by B&W/EPRI program and TVA/B&W 20 MW pilot plant by early '84.

B&W believes that its development program and TVA/B&W 20 MW pilot will serve as a Demonstration Plant for large industrial size AFBC boilers as well as the pilot step for utility size units.

Fluidized bed combustion for utility sized boilers must be demonstrated in the 200 MW size range; boiler manufacturers cannot afford to fund this effort given the state of the economy. Electric Utilities may not be able to fund program given their financial difficulties.

Economic studies should be expanded to cover low rank utility fuels where fluidized bed boilers may have greater cost advantages vs. conventional boilers with scrubbers.

The utility industry is gun-shy of new technologies unless reliability, bus-bar generating cost and construction schedules can be demonstrated.

Mr. ERTEL. Thank you very much, Mr. Smith, for your discussion and development of the fluidized bed technology.

We will have the rest of the testimony and then return to you for questions.

Our next witness is Kurt Yeager, director of coal combustion systems at EPRI.

Mr. YEAGER. Thank you, Mr. Chairman.

I am Kurt E. Yeager, director of the Coal Combustion Systems Division of the Electric Power Research Institute [EPRI] headquartered in Palo Alto, Calif. [EPRI] was established by the electric utility industry in January 1973 to plan and manage a comprehensive research and development program for the entire industry. Our 1981 program investment is \$220 million, with funding provided by voluntary contributions from the utility industry.

Over the next 5 years, EPRI will direct nearly \$600 million to improved coal utilization technology plus an additional \$150 million to environmental assessment. My testimony today will focus on coal cleaning and its potential for electric utility application; both in a cost-effective and environmental capacity.

The importance of coal is underscored by the fact that today we are burning 700 million tons per year. In expanding its use of coal, the electric utility industry has learned that the value of improved coal quality will be site and coal specific, and the cheapest coal does not necessarily produce the lowest cost electricity. One important method for improving and maintaining coal quality is coal cleaning. Coal cleaning is the generic name for technological processes that remove mineral impurities from coal.

In chemical cleaning, more complete separation of ash and organic, as well as pyritic sulphur is possible. Chemical techniques range from acid leaching to solvent refining which dissolves the coal under increased temperature and pressure. However, such chemical methods may more than double the cost of clean coal. Nevertheless, they may have significant application in coal cleaning for industrial use or for intensively cleaning specific fractions of coal. This is one area where additional development activity is strongly recommended. In the past, conventional coal cleaning has been developed primarily for cleaning metallurgical grade coals. Today, essentially all commercial coal cleaning relies on physical separation methods.

Why is there a continued interest in coal cleaning research and development, and why is the utility industry supporting a coal quality R. & D. program? These two questions have a common answer: economics. The industry has always been capable of designing units for any particular coal quality, but coal quality has been decreasing over the past decade because high quality reserves are being depleted and mine mechanization has increased to improve productivity. Unfortunately it also ends up increasing the amount of noncombustible material in the process. There has also been a corresponding decrease in unit performance and availability over the same period that run-of-mine quality has decreased. The utility industry is attempting to determine the degree to which these conditions are related and the effect of coal quality on the cost of power production.

Because of the heterogeneous nature of coal, the cleanability and associated cost and benefits can vary widely. A recently published EPRI report—CS-1622—has considered this variability by examining seven steam coal/power plant combinations at the three physical coal cleaning levels. The results indicate the following: Coal ash content was reduced by 10 to 70 percent and up to 35 percent of the total sulphur was removed. There were also cases, however, where sulphur removed was substantially less. Cost savings in coal transportation, coal handling and waste disposal done were in the range of \$1 to \$7 million/1,000 MWe/yr.

The report also concluded that capital investment associated with coal cleaning was more than offset by savings in powerplant capital cost in five of the seven cases evaluated.

A number of individual utilities have also examined the potential for improving powerplant reliability and maintenance. This has indicated direct relationships between reduction in abrasive pyritic sulphur and ash forming material and improved boiler availability. For individual boilers, improvement in availability therefore appears achievable in many cases through physical cleaning methods. The potential value is underscored by the fact that each one percent increase in plant availability is conservatively worth at least \$1.5 million/1,000 MWe/yr.

The third major benefit accruing through coal cleaning is emission reduction. With regard to sulphur removal, physical coal cleaning is most effective when used with coal where pyritic sulphur content is high. Coals of this type are mined in northern Appalachia and the eastern Midwest. The desulfurization potential is determined by laboratory washability tests on specific coal samples.

Unfortunately, our washability data base is limited and while the numbers are indicative of what can be achieved, they must be taken carefully when applied to any specific coal. In trying to better determine the cleaning characteristics not only under laboratory conditions, but more importantly under commercial conditions, the utility industry through EPRI, performs research, development and demonstration in the areas of coal cleaning, moisture reduction, handling, instrumentation, control systems, plus assessing the effects of coal quality on powerplants and coal conversion processes. This program involves an EPRI commitment of more than \$6 million a year plus significant cofunding by individual utilities and others. A focal point for this program is the CCTF located

near Homer City, Pa. [See attached.] Built entirely with private funds at a cost of \$15 million, this is the Nation's newest and most advanced coal cleaning test facility. Based on commercial scale equipment, the CCTF is demonstration scale with a maximum coal handling rate of 100 tons per hour. Unlike other test facilities, it is not dedicated to a single cleaning process but can accommodate a variety of projects resulting from EPRI research as well as others in the coal R. & D. community.

The major objectives of this facility include determining the cleaning characteristics of steam coal—this is important as each company examines the costs and benefits of improving coal quality for use in its particular situation—accelerating the transfer of improved cleaning equipment to commercial application, demonstrating improved coal sampling and analytical procedures, developing, and maintain utility oriented national coal quality data base and providing training for coal preparation engineers and cleaning plant operators.

The CCTF is sponsored by EPRI; Pennsylvania Electric Co., a subsidiary of GPU Service Corp.; New York State Electric and Gas Corp.; and the Empire State Electric Energy Research Corp. (ESEERCO). All interested coal users and producers are invited to participate in the testing and evaluation program.

I would like to add one additional area before I get into my conclusions, and that is with respect to coal slurry fuels, which was mentioned by one of the earlier members of the panel.

Today's technology also permits preparation of pumpable, stable, coal-water slurries, containing about 70 percent coal. This type of slurry is made with clean coal (coal with low ash content), as an oil replacement option. That is not to say it will replace it on a one-to-one basis, but to many companies on the east coast, where oil costs are extremely high and the assurance of supply is very uncertain, it is an important insurance policy. An important synergism resulting from this approach is the ability to use the wet fines from coal cleaning processes directly as a fuel, thus avoiding the energy intensive drying step which is now perhaps the major factor limiting the degree to which we are able to clean steam coal. This encourages development of cleaning processes which are designed to increase and recover rather than eliminate and reject fines production.

In conclusion, I would like to comment on several issues and associated recommendations. Cleaning of steam coal to remove sulfur and ash is an increasingly important option for the utility industry. Substantial cost savings as well as emission reductions can be achieved in many instances, not only for new, but more importantly, for existing powerplants. This results from reduced coal transportation and handling costs, reduced maintenance and improved plant availability, improved plant performance and reduced power consumption, plus reduced waste disposal costs and reduced flue gas cleanup costs.

Not every one of these advantages can be applied to every single powerplant, but certainly many powerplants and many companies in this country can and are applying coal cleaning to an increasing degree to good advantage economically and environmentally. The areas wherein additional research and development should be pur-

sued to significantly improve the application of coal cleaning are as follows: First, we need better methods to estimate how coal composition and cleanability varies throughout a reserve. We need better techniques to determine how to obtain representative test samples—such as those that will be tested at the EPRI coal cleaning test facility—from reserves. When we build a plant, we build it for 30 to 50 years of operation. The coal that comes out of the mine face the day we start that plant may bear no relation to the coal that has been purchased under long-term contract for use in that plant 10, 20, 30 years in the future. Unless we understand how that variability changes and how it affects the quality of coal we deliver to the plant, we are going to be limited in our applications.

We need techniques to inexpensively recover large, representative samples from deep coal reserves and convert these into a data base that will allow conversion of reserves and washability estimates into accurate estimates of actual clean coal quality and production potential. This is one major objective of the CCTF. Also needed are techniques for cleaning and upgrading lower rank western coals. Of particular importance are opportunities to reduce the moisture and alkali metal content. The latter is particularly important to reducing boiler costs and to improve the capability of these coals for use in existing powerplants.

We need more efficient and economic fine coal cleaning and recovery techniques for direct use, as well as in coal slurry preparation. Similarly, more economical chemical cleaning techniques providing more complete sulfur and ash removal, and automated cleaning process control and on-line continuous monitoring techniques should receive increased R. & D. emphasis. It is estimated that a 5-percent increase in cleaning plant energy recovery can be achieved through improved process control.

Our growing national dependence on coal is both an opportunity and demand that the coal producers, equipment suppliers, coal purchasers, and Federal Government integrate their efforts to most economically make progress toward assuring improved coal quality. EPRI looks forward to joining in this challenge.

I thank you.

[The prepared statement of Kurt E. Yeager follows:]

PREPARED STATEMENT OF KURT E. YEAGER, DIRECTOR, COAL COMBUSTION SYSTEMS
DIVISION, ELECTRIC POWER RESEARCH INSTITUTE

COAL CLEANING TECHNOLOGY FOR THE ELECTRIC UTILITY INDUSTRY

Introductory Statement

I am Kurt E. Yeager, Director of the Coal Combustion Systems Division of the Electric Power Research Institute (EPRI) headquartered in Palo Alto, California. EPRI was established by the electric utility industry in January, 1973 to plan and manage a comprehensive research and development program for the entire industry. Our 1981 program investment is \$220 million, with funding provided by voluntary contributions from the utility industry.

Over the next 5 years, EPRI will direct nearly \$600 million to improved coal utilization technology plus an additional \$150 million to environmental assessment. My testimony today will focus on coal cleaning and its potential for electric utility application, both in a cost effective and environmental capacity.¹

¹ "More Coal Per Ton." *EPRI Journal*, Vol. 4, No. 5, Palo Alto, CA, June 1979.

THE ROLE OF COAL

If coal is to be the cost effective energy resource and workhorse for the decades ahead in the production of electricity, we must apply what we have learned from the Experiences of this past in establishing the basis for future coal quality decisions.

In applying these consideration, the Electric utility industry has learned that the value of improved coal quality will be site and coal specific, and the cheapest coal does not necessarily produce the lowest cost electricity.²

WHAT IS COAL CLEANING

One important method for improving and maintaining coal quality is coal cleaning. Coal cleaning is the generic name for technological processes that remove mineral impurities from coal. These processes can be separated into physical or chemical methods. In the former, physical (specific gravity and surface) characteristics are used to separate organic coal from the inorganic, pyritic sulfur and ash producing minerals. The process is made up of several unit operations tailored to the characteristics of the coal and its end use.

In chemical cleaning, more complete separation of ash and organic, as well as pyritic, sulfur is possible. Chemical techniques range from acid leaching to solvent refining which dissolves the coal under increased temperature and pressure. However, such chemical methods may more than double the cost of clean coal. Nevertheless, they may have significant application in coal cleaning for industrial use or for intensively cleaning specific fractions of coal.

Today, essentially all commercial coal cleaning relies on physical separation methods.

Why is there a continued interest in coal cleaning research and development, and why is the utility industry supporting a coal quality R&D program? These two questions have a common answer: Economics. The industry has always been capable of designing units for any particular coal quality, but coal quality has been decreasing over the past decade because high quality reserves are being depleted and mine mechanization has increased to improve productivity but it ends up forcing out non-combustible material in the process. There has also been a decrease in unit performance and availability over the same period that run-of-mine quality has decreased. The utility industry is attempting to determine the degree to which these conditions are related and the effect of coal quality on the cost of power production.

Because of the heterogeneous nature of coal, the cleanability and associated cost and benefits can vary widely. A recently published EPRI report (CS-1622) has considered this variability by examining seven steam coal/power plant combinations at the three physical coal cleaning levels. The results indicate the following:

Coal ash content was reduced by 10 to 70 percent and up to 35 percent of the total sulfur was removed. There were also cases, however where sulfur removal was substantially less.

Cost Savings in coal transportation, coal handling and waste disposal were in the range of \$1-7 million/1,000 MWe/yr. The report also concluded that capital investment associated with coal cleaning was more than offset by savings in powerplant capital cost in 5 of 7 cases evaluated.

A number of individual utilities have also examined the potential for improving powerplant reliability and maintenance. This has indicated direct relationships between reduction in abrasive pyritic sulfur and ash forming material and improved boiler availability. For individual boilers, improvement in availability appears achievable in many cases through physical cleaning methods. The potential value is underscored by the fact that each 1 percent increase in plant availability is conservatively worth at least \$1.5 million/1000 MWe/yr.

The third major benefit accruing through coal cleaning is emission reduction. With regard to sulfur removal, physical coal cleaning is most effective when used with coal where pyritic sulfur content is high. Coals of this type are mined in Northern Appalachia and the Eastern Midwest. The desulfurization potential is determined by laboratory washability tests on specific coal samples.³

EPRI⁴ performs research, development and demonstration in the areas of coal cleaning, moisture reduction, handling, instrumentation, control systems, plus as-

² "Evaluation of Physical/Chemical Coal Cleaning and flue Gas desulfurization," EPA-600/7-79-250, TVA, Office of power, Washington, DC, Nov. 1979.

³ Blackmore, Gerald, "The outlook for Steam Coal as Used by Electric Utilities," American Mining Congress 1980 Mining Convention, San Francisco, CA, Sept. 1980.

⁴ Trelice, D. N., and Clifford, K. L., "Coal Cleaning Test Facility—Research and Development at a Demonstration Scale," 1981 AIME Annual Meeting, Chicago, IL, Feb. 1981.

program involves an EPRI commitment of more than \$6 million a year plus significant cofunding by individual utilities and others. A focal point for this program is the CCTF located near Homer City, Pennsylvania (see attached). Built entirely with private funds at a cost of \$15 million, this is the Nation's newest and most advanced coal cleaning test facility. Based on commercial scale equipment, the CCTF is demonstration scale with a maximum coal handling rate of 100 tons per hour. Unlike other test facilities, it is not dedicated to a single cleaning process but can accommodate a variety of projects resulting from EPRI research as well as other in the coal R&D community.⁵

The CCTF is sponsored by EPRI; Pennsylvania Electric Company, a subsidiary of GPU Service Corporation; New York State Electric and Gas Corporation; and the Empire State Electric Energy Research Corporation (ESEERCO). All interested coal users and producers are invited to participate in the testing and evaluation program.⁶

Cleaning of steam coal to remove sulfur and ash is an increasingly important option for the utility industry. Substantial cost savings as well as emission reductions can be achieved in many instances, not only for new, but more importantly, for existing power plants, and these savings result from five primary areas: Reduced coal transportation and handling costs; reduced maintenance and improved plant availability; improved plant performance and reduced power consumption; reduced waste disposal costs; and reduced flue gas cleanup costs.

First we need better methods to estimate how coal composition and cleanability varies throughout a reserve.

We need better techniques to determine how to obtain representative test samples (such as those that will be tested at the EPRI Coal Cleaning Test Facility) from reserves.⁷

Techniques to inexpensively recover large, representative samples from deep coal reserves.

A data base that will allow conversion of reserves and washability estimates into accurate estimates of actual clean coal quality and production. This is one major objective of the CCTF.

Techniques for cleaning and upgrading lower rank western coals. Of particular importance are opportunities to reduce the moisture and alkali metal content. The latter is particularly important to reducing boiler costs and to improve the capability of these coals for use in existing power plants.

More efficient and economical fine coal cleaning and recovery techniques for direct use, as well as in coal slurry preparation.

More economical chemical cleaning techniques providing more complete sulfur and ash removal.

Automated cleaning process control and on-line continuous monitoring techniques. It is estimated that a 5-percent increase in cleaning plant energy recovery can be achieved through improved process control.

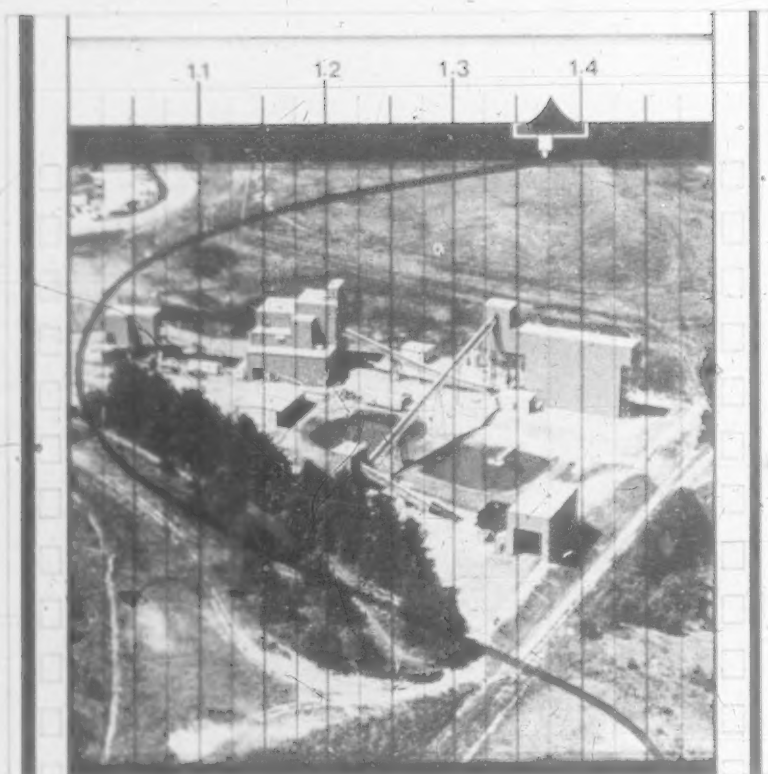
Our growing national dependence on coal is both an opportunity and demand that the coal producers, equipment suppliers, coal purchasers and Federal government integrate their efforts to most economically make progress toward assuring improved coal quality. EPRI looks forward to joining in this challenge.

⁵ "Impact of Coal Cleaning on the Cost of New Coal-Fired Power Generation," EPRI CS-1622, Palo Alto, CA, Bechtel National, Inc., March 1981.

⁶ "Coal Resources and Sulfur Emission Regulations: A Summary of Eight Eastern and Mid-western States," EPA-600/7-18-086, Research Triangle Park, N.C., Teknekron, May 1981.

⁷ Holt, E. C., Barrett, R. E., and Frank, R. L., "Examining Relationships Between Coal Characteristics and the Performance of TVA Power Plants," 1981 Joint Power Generation Conference, St. Louis, Mo., Oct. 1981.

EPRI CCTF



Electric Power Research Institute
Coal Cleaning Test Facility

Advanced Coal Cleaning Facility

by James H. Smith

The Advanced Coal Cleaning Facility (ACCF) is a state-of-the-art research and development facility located at the Electric Power Research Institute (EPRI) in Charlotte, North Carolina. The facility is designed to evaluate and optimize coal cleaning processes for power plants.

Coal Processing Test Facility

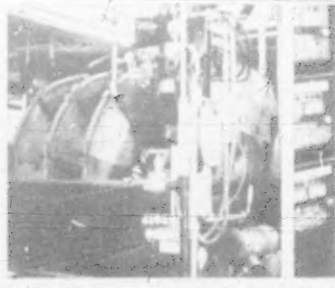
by James H. Smith

The Coal Processing Test Facility (CPTF) is a state-of-the-art research and development facility located at the Electric Power Research Institute (EPRI) in Charlotte, North Carolina. The facility is designed to evaluate and optimize coal processing processes for power plants.

Coal Processing Test Facility

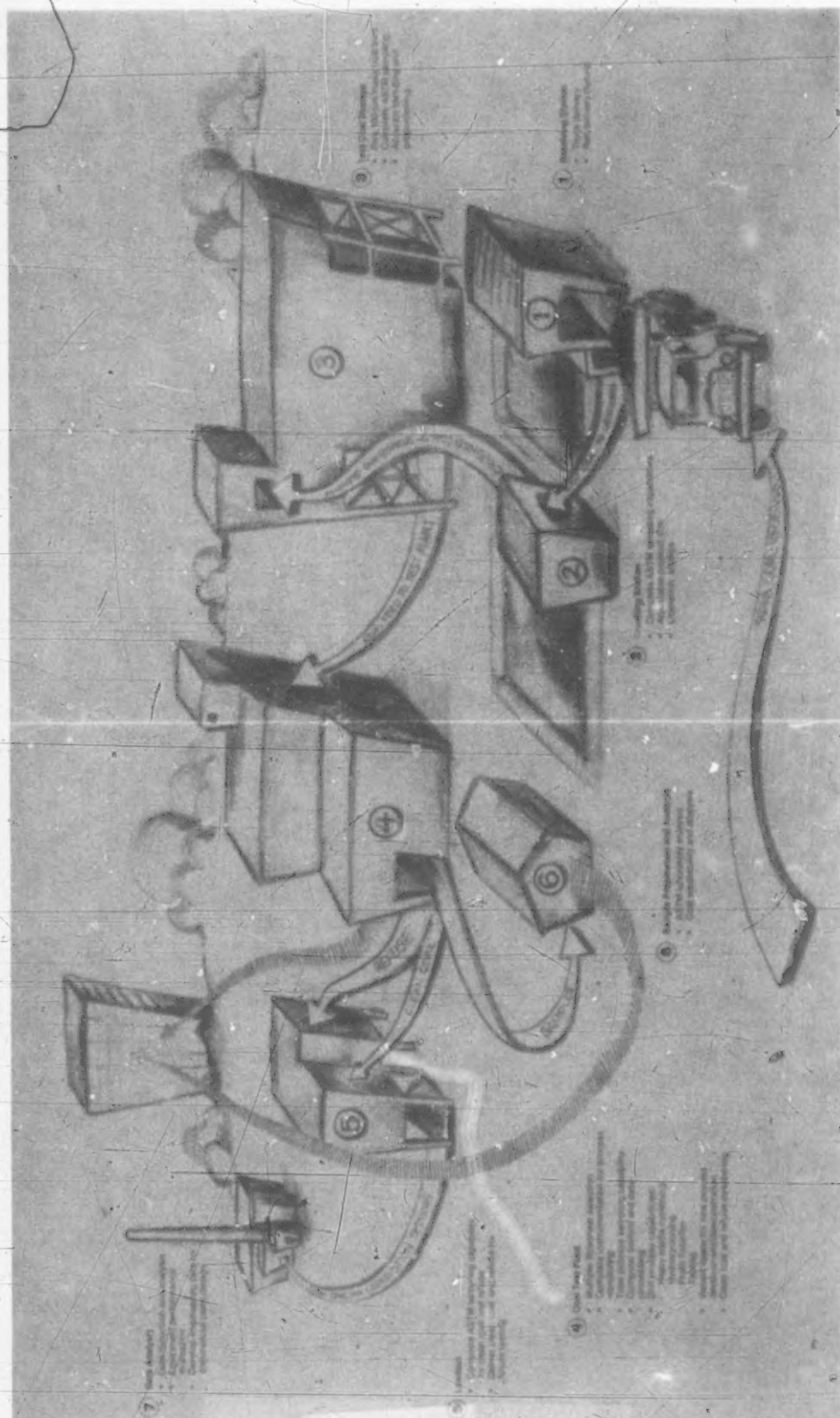
by James H. Smith

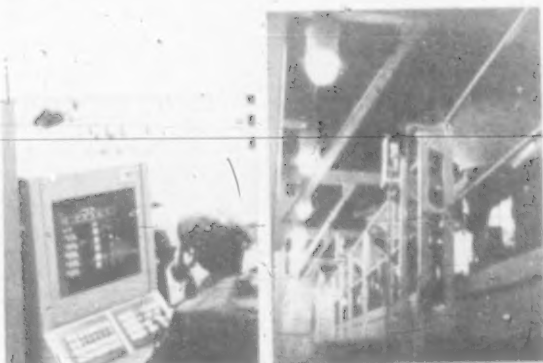
The Coal Processing Test Facility (CPTF) is a state-of-the-art research and development facility located at the Electric Power Research Institute (EPRI) in Charlotte, North Carolina. The facility is designed to evaluate and optimize coal processing processes for power plants.



EPRI

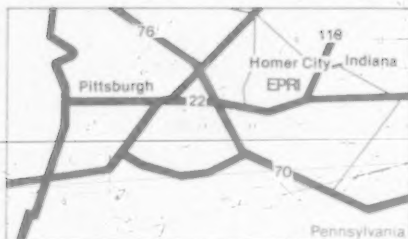
Electric Power Research Institute
Coal Cleaning Test Facility





For Further Information

Contact EPRI at any of the offices listed below for more information and/or arrangements of a CCTF visit.



Electric Power Research Institute
4318 N. Pike 75J 203
Morgantown, PA 15146
(412) 856-7120

Electric Power Research Institute
P.O. Box 98
Homer City, PA 15746
(412) 479-3503

Electric Power Research Institute
P.O. Box 10412
3412 Hillview Ave
Palo Alto, CA 94304
(415) 855-2000

**KAISER
ENGINEERS**

Mr. ERTEL. Thank you very much for your excellent outline of the coal cleaning technology. It is something that doesn't seem to get much attention in this country, but it is something important to me. We will be returning to you with questions.

Mr. ERTEL. Our next witness is Tobias Anthony, director of Research-Cottrell, Inc. We welcome you.

Mr. ANTHONY. Good afternoon, Mr. Chairman and members of the committee. I have submitted my testimony and I would like to summarize it, rather than go through the whole thing again.

Mr. ERTEL. Your testimony will be incorporated into the record without objection.

Mr. ANTHONY. I am privileged once again to be here to discuss coal utilization or, as I like to refer to it—burning coal cleanly.

I am happy to report the DOE has organized a division along the lines of a suggestion I made before your committee on May 20.

The new Division is the Control Systems Division in the Office of Coal Utilization. Its responsibilities are to conduct and manage R. & D. in coal postcombustion, combustion and precombustion phases at a level at which the Department can trade off developments to arrive at the most cost-effective one.

It is essential to the goal of coal dependence, and therefore energy independence, that we burn it cleanly. This means, however, that for the rest of the century, we may not be burning it economically.

How could this be? We have huge scrubbers to remove sulfur oxide, precipitators and fabric filters to remove particulates and separate thermal de-nox equipment to remove nitrogen oxides, a popular criteria pollutant discussed in connection with acid rain.

Wisely, DOE recognized the economics possible in combining control in one system and is sponsoring research to develop an E-beam, combined control system.

But if that system will not be the panacea, they are sponsoring R. & D. in combustion and precombustion areas that will be discussed here today.

This three-path approach will provide the technology we need by the end of the century.

Well, if the concept is so good, why is DOE's budget being slashed and why will they be phased out in 1983? Ostensibly, the administration believes the private sector will take over. In my estimation, no one in the private sector will use internal funds exclusively, unless they are foolish. The reasons are simple:

(a) The market is driven by the Clean Air Act scheduled for change every 4 years. Change can obsolete equipment.

(b) New source performance standards at the stroke of a pen, and for no good economic or technical reasons, can obsolete equipment.

(c) R. & D. payback periods typically are 8 to 10 years for brand-new technology development. Too long a period of investment in a market controlled by the Federal Government.

Mr. Chairman, like it or not, the Federal Government controls the coal utilization market. Rest comfortably that postcombustion technology works, but may not be the most economical way to go.

There are 128 FGD systems installed on 48,460 megawatts of electric generating capacity. But that technology will be almost 40

years old before it can be replaced by new technology. The reason is it takes 8 to 10 years to build a coal-fired powerplant and another 10 to 20 years to retire it.

No other technology is ready to replace direct-fired furnaces with back-end pollution control equipment.

We should not be slashing the Control Systems Division budget; we should be doubling it. Coal dependency, economically and environmentally arrived at, is critical to our security and the Federal Government must lead the way to that goal.

Thank you.

[The prepared statement of Mr. Anthony follows:]

STATEMENT OF
TOBIAS ANTHONY
DIRECTOR BUSINESS DEVELOPMENT
AND
WASHINGTON AFFAIRS
RESEARCH-COTTRELL INC

Good afternoon, Mr. Chairman and members of the House Subcommittee on Energy Development and Applications. I am privileged to be here once again to testify on the subject of burning coal cleanly and economically. It was my privilege to testify before you in May on this subject so I'd like to pick up from there.

Burning coal cleanly, today, and for the rest of the century means direct combustion followed by stack gas clean-up equipment or what we call post-combustion clean-up. For the next 20 years or so, scrubbers will be used to control sulfur dioxide and electrostatic precipitators or fabric filters will be used to control particulates.

The reasons are simple. Electric utilities burn two-thirds of our coal and powerplants built today will be operational in ten years and last another ten or twenty years. If all existing powerplants were retired today, most utilities would stay with direct combustion meaning nothing would change for at least 20 years.

We Can Become Coal Dependant - If?

This poses an interesting dilemma for a nation that must, and will probably, become coal dependent. According to the Columbia Institute for Political Research, 36% of the 100 quads of energy we will use in the year 2000 will be derived from coal which will allow us to reduce imports of oil from 20%, currently, to 5%. We are well on our way to very likely reaching the goal of 1.2 million tons per year by 1985 called for by President Carter in April 1977.

We can remove sulfur oxides, particulates and are on our way toward mature denox systems. Currently, there are a total of 28 FGD systems installed on 49,460 MW of electric generating capacity.

Roughly, a third of all operating units are treating combustion gases from furnaces firing coals with sulfur levels in excess of 3%. A majority of systems operate in excess of 90% availability albeit at appreciable cost to utilities. After 10 years of painful experience adapting demonstrated technology to commercial use, we are finally arriving at that point where scrubbers are working.

Staying with the subject of scrubbers (FGD systems) a little longer. They were developed by the private sector largely with private funds. Federal money was used for demonstration, test and evaluation as clearly described in A Legislative History of the Clean Air Act Amendments of 1970, published in January 1974. Electrostatic precipitators, fabric filters and spray dryers were also developed with private funds, essentially.

I doubt very much if the private sector will ever again invest substantial internal funds in air pollution R&D. Once again the reasons are simple.

The Private Sector is Disillusioned

First, it takes a ten year payback period before an investment in R&D will return profits. Since the Clean Air Act can change every four years, technology can become obsolete before the payback period is ended. For example, for decades, weighted wire precipitators were the basic technology for control of particulates when reductions of 80-85% were called for. When the 1977 Clean Air Act was passed 99% reductions favored rigid discharge electrodes and fabric filters, thereby eliminating the older technology. Now it is one thing to track buyer's spending attitudes to predict changing technologies and an entirely different matter when an Administrator of the EPA can change requirements in a morning press conference.

Once again, the Administrator in 1979 eliminated another technology. Mr. Costle determined that spray dryers should be used to control sulfur dioxide from combustion of low-sulfur coals. So, he allowed a 70% reduction of sulfur dioxide in flue gases to make spray dryers more competitive with wet scrubbers, but maintained a 90% reduction limit on emissions from burning high sulfur coals. Wet scrubbers were eliminated from the marketplace.

Secondly, the Clean Air Act calls for review of NSPS every four years meaning emission limits can change every four years. The last time the Clean Air Act was amended was 1977. It took two years to debate the amendments and another two years to debate changes to the NSPS which was promulgated in 1979. So in effect, these standards were in effect one year, when it became time in 1981 to consider revising the Act again.

Users of pollution control equipment literally sat and waited the outcome. Since it takes 8-10 years to construct a powerplant, it is an easy matter to delay purchasing control equipment with the expectation it, too, might change.

Thirdly, Congress has the power to create huge markets or cut them drastically in short order. For example, the 1977 Act called for percent reduction of sulfur oxide emissions from all coals to protect eastern, high-sulfur coal-producing states. As a result the scrubber market for equipment mushroomed from about \$100 million in 1977 to \$800 million in 1980. Now, if that requirement is removed, we expect to lose half of the scrubber market.

Keeping that requirement to maintain a huge market is bad policy, as was the initial rationale for instituting the requirement.

In summary, I do not expect the private sector to invest its internal funds in long range R&D in order to burn coal cleanly.

Finally, the Clean Air Act is devastating our industry. One of our leaders, Envirotech, has been forced to sell off its assets because of government policy on air and water. Peabody International, another excellent firm, split in two in order to isolate its less profitable environmental business from its energy companies. CEA is in Chapter 11. Those of us remaining are working on margins that do not allow for investing in long range R&D. Remember I am talking about the leaders in the pollution control industry.

So, how can we become coal dependent while burning coal cleanly and economically? The DOE Fossil Energy Research and Development program is the right approach. In particular, last year DOE organized the Control Technology Systems Division in the Office of Coal Utilization and Extraction. That move placed responsibility for post-combustion, combustion and pre-combustion technology development in one division at the proper technical level. Now, one authority can make trade-offs among the three phases of combustion and arrive at the most cost-effective approaches.

Why Put the Control Systems Division Out of Business?

It is the right approach for other reasons. The government will have to fund R&D up to the pre-commercial phase in order to cut payback periods in half. In other words, DOE or EPA will have to pay for the early risk period to bring a development close to commercialization. Then and only then, will the private sector risk developing, and penetrating the market. The Control Technology Systems Division's control technology and coal preparation program would accomplish the right marriage between industry and government.

In my opinion it would be wise to increase funding over 1980 levels. In particular, I can't understand cuts in coal preparation budgets. If we could develop a super clean coal which is the intent of the program, we could solve many thorny issues.

- (a) The acid rain issue would evaporate.
- (b) Utility and non-utility firms would continue to burn coal directly.
- (c) It could be used in coal/water or coal/oil mixtures for for direct firing in homes, office buildings and shopping centers.
- (d) Waste and residue would be confined to mines instead of sludge ponds and fly-ash piles.
- (e) A super-clean coal is inherently more economical than using scrubbers.

Congress Must Push Ahead

Congressional support for DOE's program could make the difference. We could have a "super clean" coal in wide commercial use before the end of the century which could be burned without major changes to furnaces.

Meanwhile, it is important to continue to work on near term options. The combined NO_x , SO_x and particulate control program could save \$50/kw over conventional methods, according to TVA. Their studies show that a lime/limestone scrubber plus separate NO_x control would amount to \$255/kw in capital cost and 22 mills/kwh while a mature E-beam combined system would cost \$205/kw and more importantly 15 mills/kwh.

The other panelists will discuss other developments. Pressurized and atmospheric fluidized bed technologies are especially

attractive to non-utility industries. Limestone injection offers a possibility for utilities since modification of the furnace box would be minimal.

Why fund an array of technology developments? It is common knowledge only one in five R&D projects meets market expectations. We need to have more economical systems in the short term to buy time for the panacea of the future. Finally, if you accept my scenario, the government must lead the way which means it must hedge its options. No one is smart enough to pick the one, future panacea.

Thank you.

Mr. ERTEL. Thank you very much, Mr. Anthony, for your testimony, and I have also tried to listen and read your testimony at the same time.

I find both phases of it interesting and would like to question you on it, but we have two bells up and we have to go to the floor to vote, so if you will be around, we will be back in a few moments.

At this point, the subcommittee will stand adjourned for a period of 10 minutes.

[Recess.]

Mr. ERTEL. The subcommittee will come to order.

Mr. Smith, I was interested in your testimony on the fluidized bed technology. You indicate in your testimony that we would have to move to a much larger fuel utilization plant for a lot of research and development, that you along with your compatriots were doing such, but somehow I wasn't quite sure when you moved to that larger plant about who pays the tab. Who is going to put the money in?

Mr. SMITH. This is the demonstration plant that I referred to.

Mr. ERTEL. Yes.

Mr. SMITH. I do not think there is any question in our mind that we would have to make some business decision about our involvement in such a plant. One way of involving ourselves is to provide resources and facilities and some cost-sharing with such a plant.

Mr. ERTEL. Cost-sharing with whom?

Mr. SMITH. Cost-sharing with those who would build the plant. We think that such a plant would require funding, as we see it today, from outside of the electric utility industry, but our perspective has to do with the current low order level of the fossil business, which in some respects has to do with the financial condition of the electric utilities. So therefore, we would expect at this time that the electric utilities, a few major utilities, probably, themselves could not go it alone in such a development plant because of the large risks that would be there.

Mr. ERTEL. You seem to be talking around the question I am trying to get at.

Are you expecting Government money?

Mr. SMITH. We would expect Government money.

Mr. ERTEL. In what quantities?

Mr. SMITH. Well, I do not think that I could speak to the quantities right now. Perhaps Mr. Yeager has a better perspective of what the overall plant cost would be. But we are talking a 200-megawatt plant and the average cost of a plant like that today, for a commercial facility, would be on the order of \$800 to \$900 a kilowatt. So we are talking in the vicinity of \$180, \$200 million.

Mr. ERTEL. Well, the thrust of everything I see out of this administration is not to fund, or to participate in the funding of any demonstration programs. If that is true, and I think it is, what does that do to your program, if anything?

Mr. SMITH. If that is true, then B. & W. would, I believe, have the same optimism as far as what is required and when it is required, but the private sector would have to make the decision to develop the technology on its own and I do not know if I can answer that question.

Perhaps Mr. Yeager, who represents that industry, would be better able to do so than I would.

Mr. ERTEL. Would you like to take a try at that, Mr. Yeager.

Mr. YEAGER. I will give you a perspective if I may, sir, since DOE has never planned to participate in such a demonstration. Next week, a letter will be going from our president to the chief executive officers of each of the power companies in this country, indicating our desire to proceed with the demonstration of an atmospheric fluid bed combustion technology if the 20-megawatt pilot unit described earlier, soon beginning operation at TVA, is as successful as we hope. This will lead then to a consortium of private sector firms, utility companies and others, who are prepared to underwrite a substantial portion of the cost of this plant.

We have substantial funding in our budget for that kind of a plant. The difficulty that is being caused by the Federal sector is the loss of appropriated funds for this activity to TVA, who have long planned to build such a demonstration. The only way they can now provide funding is entirely out of their own power generation funds. That makes it much more difficult, essentially impossible, for TVA to do it on their own. So we will have to put together a consortium to do it. Whether we will be successful I can't guarantee you today, but that is the only option left for us.

Mr. ERTEL. I have to say to you, it sounds like we are going around Robin's barn. I don't consider the utilities industry to be in the private sector. They are in the public domain, most of them; some of them are investor owned, I understand that. Yet they are in a monopoly position, their return is set by regulators. They are basically public corporations.

The investor gets a return on the stock he puts into it, which is really the same thing as a return on a bond. He has some risks, though we try to minimize that.

So aren't we really just playing games when we say the utility industry is a private sector? We are going to transfer all these costs to the private sector? Aren't we really just saying we are transferring it to another arm of the public sector?

Mr. YEAGER. Most utility stockholders might argue that.

Mr. ERTEL. So are you in favor of this idea?

And I look at the new budget recommendations, in which there are no demonstration projects, at least not new ones. Frankly, I am not even sure they are going to complete the old ones or the ones in process.

Where do you come down on that as a representative of the "private sector," because I am not sure you are in that private sector?

Mr. YEAGER. Well, it forces the situation—it is certainly not a situation that I or anyone else connected with this industry appreciates or wants to have happen. But if we are going to move ahead, we are going to have to figure out some alternate ways to deal with the problem of financing demonstrations. We are trying to take the first steps to put together that kind of a capability in the absence of Federal participation.

We would much prefer to see the Federal Government maintain its role in terms of bringing forth new technology. Without that role it is going to take longer, probably going to cost more and a lot of other things that need to be done will be sacrificed. They simply can't be funded.

If we are successful in an atmospheric fluid bed combustor demonstration, we will sacrifice many other things that would have been done instead.

Mr. ERTEL. Did any of your people ever express their views to OMB?

Mr. YEAGER. Oh, yes, sir.

Mr. ERTEL. I would hope so. Let me ask Mr. Smith some questions about the fluidized bed.

What do you consider the biggest problem with the commercialization of fluidized bed at the present time?

Mr. SMITH. The biggest problem that we see in commercialization of the utility size units is the one of scaling up the size of the plant from 20 megawatts to perhaps 300 or 400 megawatt average size. The average size of utility units purchased from Babcock & Wilcox for the past 10 years has been around 650 megawatts. At these sizes, these powerplants have considerable economies of scale.

Now there are some future trends that we see that may make smaller powerplants which are economical, a trend for utilities in the future. If the technology of fluidized bed, in that size, is proven, it still will be an extrapolation of a factor of 20 from the TVA pilot facility. It is kind of the difference between a 40-story building for a full-size boiler and a house. That is the kind of scale up we are talking about.

Mr. ERTEL. Well, I have been told in general terms that pressurized fluidized bed combustion is much more amenable to large-scale utilization as compared to atmospheric, which would be more of an industrial-type application, smaller.

Is that true? If it is true, then why are you trying to scale up the atmospheric fluidized bed rather than being in a pressurized mode for these large utilizations by utilities?

Mr. SMITH. We don't think it is true, as a company. Our priority, obviously, is with the atmospheric fluid bed. Our expenditures on pressurized fluid bed are not measurable compared to the \$25 million I spoke of on the atmospheric.

We see that the pressurized fluid bed would be an extension to the technology base of the atmospheric units and may grow into

being 5 to 10 years after the successful demonstration of utility-size atmospheric units.

Whenever you deal with a boiler in a typical environment, adding the pressurization step to the boiler is a considerable problem from a mechanical standpoint. It looks good on paper to us; there are a lot of questions that have to be answered before B. & W. would say that yes, we see more promise in pressurized fluid bed than we see in atmospheric fluid bed.

Mr. ERTEL. Let me go a bit further.

On the commercialization of fluidized bed, what do you need to force that into the base of the country right now? What do you need? Money? I suspect that is true, but let's eliminate Government money because I do not think that is there. Then how do you get that technology utilized?

Mr. SMITH. Well, from our standpoint we see that there may be a large market for large industrial-size fluidized bed units. We feel that the 20 megawatt TVA pilot, and a very large test program for that pilot, which is being funded by EPRI, will basically answer the questions that we have—it will answer the problems that we must solve prior to commercialization of units that the typical industrial customer would purchase, up to perhaps around half-a-million pounds per hour of steam. So that is the first step that we see.

I didn't address this in my testimony other than to say that we feel that this step will occur sometime during the TVA pilot test which starts in May of 1982 and completes in March of 1984. So we will be ready sometime in that period to offer commercial warranties and guarantees on that equipment.

The step up in utility size is not one in which we are prepared to go alone as a manufacturer. We just simply can't afford the cost of that—that kind of R. & D. cost.

Mr. ERTEL. We have an existing pilot project, an experimental one, atmospheric fluidized bed in my district or close to it, which is doing a lot of test runs right now, not on the types of coals that you are using but on culm, which is a low-quality coal. There is some coal there but most of it is rock, and so on.

Have you had any input into that, any transfer of information from that to yours? Is it possible that it will do anything for you?

Mr. SMITH. We are aware of it. Our technology is somewhat different than the technology being used in Shamokin. We feel for an industry to be healthy that it should have several competitors with different technologies. Our technology is considerably different, as I said, and normally we develop our technology and very rarely ever copy something.

Mr. ERTEL. I am not asking for copy. Certainly there is information, a learning curve, experiences can be swapped. That is the one reason you go to a conference, just to hear the shoptalk by the other guy. You pick up a lot of information, some useful, some worthless, some disinformation. Any of that kind of transfer going on?

Mr. SMITH. I would say not on that point.

Mr. ERTEL. How about EPA, do you need any waivers from EPA for your atmospheric fluidized bed technology at the present time? Do you think it will require any in the existing standards at the present time?

Mr. SMITH. No, I do not think there would be any waivers required. All of our work has been directed toward the fact that the standards would have to be met for any new equipment.

Mr. ERTEL. I am going to look to see what other notes I made during your testimony.

I had a note on page 3 where you talked about the overall savings for AFBC boilers. You said it would be 10 to 15 percent overall savings. I guess that depends somewhat on interest cost, because if in fact it is a capital intensive type of operation, and if the cost is up front, what kind of interest rate did you build into that 10 or 15 percent, because you say overall costs?

I guess that is on an annualized basis, depending on the capacity and also on the interest rates you are paying on your initial capital investment.

Mr. SMITH. That is a very good point.

Mr. ERTEL. What did you put in?

Mr. SMITH. This study was done by EPRI. Perhaps Mr. Yeager remembers the interest rate? I believe it was in the vicinity of 12 percent, but I can check the number.

Mr. YEAGER. At the time the study was done, 12 percent was used. We however are dealing with building two power plants of the same size, same conditions, different technologies, side by side at the same time. So that the interest rate that applied to one would apply to the other at that time. Any change would be at the margin less significant probably than the uncertainty we have in the costs between the two technologies.

Mr. ERTEL. When you say costs, are you talking about initial costs?

Mr. YEAGER. Both initial costs and operating costs. Frankly, I think cost savings accrued to fluid bed combustion would probably be larger during the operating period than it would be in the initial cost, especially in the early versions that are built. That comes about because it avoids the sensitivity to fuel characteristics that you have in a conventional boiler.

One of the real advantages of fluidized bed combustion is its ability to burn mine culm one day, municipal waste the next, and bituminous coal the next, with no fundamental change in the design or power output of the boiler. That has been our experience to date. That is one of the advantages we are confirming as well as avoiding having to put a scrubber on the back end of the plant to achieve environmental control requirements.

Mr. ERTEL. Does EPRI anticipate that the Tax Incentive Act of 1981 will lead to a substantial increase in EPRI's \$220 million budget per year?

Mr. YEAGER. It won't directly affect our budget, however I hope it will encourage cost-sharing in the kinds of technology developments that we are talking about, for example demonstrations that really exceed our budget.

Mr. ERTEL. I do not see how that Tax Incentive Act is going to help you one way or another.

Mr. YEAGER. Only by its intent—and you are much closer to that than I am, so I can't judge it yet—to afford opportunity for outside investors to participate in R. & D. where otherwise they might not.

Whether indeed it will do so I am not in a position to say. We have no evidence either way at this point.

Mr. ERTEL. I do not know if any of you can answer this.

The three technologies you talked about are approaches to clean coal. What is the most promising at the present time? Which one will be the most economical in the long haul? Do you have an opinion on that?

Mr. YEAGER. The only commercial one we have today is really physical coal cleaning in one form or another, which is a broad spectrum of individual processes. I would hope that eventually chemical coal cleaning can be an important element because its ability to remove sulfur and ash is much greater.

I must say at this time we do not have any efforts in development in chemical cleaning underway, frankly because we have not found any chemistries that have been sufficiently attractive economically to justify major development funding.

Mr. ERTEL. The Government is pulling back in coal cleaning, fossil fuel development area. Do you ever think you are going to find any? If you are not going to look into coal cleaning chemically, who is going to do it?

Mr. YEAGER. I think you put your finger on a very important example of the problem. Those high risks, long leadtime research and development activities which lead to fundamentally new technologies, are probably the area that is going to be sacrificed most. Even more than the other end of the development scale, because there is no way whatever you want to define the private sector as being, that it can justify those kinds of high risk development.

Mr. ERTEL. How about you, Mr. Anthony, you are disillusioned with what the private sector's role is; according to one of our leads on the things here, the private sector is disillusioned, you say.

Where are we going to go in this area?

Mr. ANTHONY. The best chances for the most economic way to burn coal is through a combination of physical cleaning and chemical cleaning. There is no question in my mind that the economics favor getting rid of the contaminants at the front end. This will take us about 20 years before we can develop a commercial system.

The main reason why it is an attractive goal is that it allows utilities to continue to burn coal in existing types of furnaces. Utilities are very reluctant to change the design of their furnaces. I wish anybody who has an investment in pressurized fluidized bed a good deal of luck and my good wishes in convincing utilities to convert from direct burning to fluidized bed. I do not think it will happen in our lifetime.

But if we had a superclean coal available today, we could use it not only in new construction but in existing construction. It would be an attractive way to get rid of this argument over acid rain in the 31 States east of the Mississippi River where utilities are now being earmarked for acid rain legislation.

There is no question in my mind that if economics favored superclean coal, they would burn it and they would not look at major design changes such as postcombustion technology or fluidized bed. And the Federal Government is the one that can develop that superclean coal and it should be done on a crash program.

We had a crash program last year on synthetic fuels called the synthetic fuels express, which fizzled out. That did an awful lot to disillusion the private sector. Those people who saw that thing blow up and then blow away said to themselves, well, we are going to be very cautious about how much money we are going to invest in these kinds of schemes. But I am sure that if the Federal Government led the way in physical and chemical coal cleaning, the private sector would jump on the bandwagon; it makes so much sense.

Mr. YEAGER. I might add one thought to back that up. One option that has progressed a long way in development in the chemical cleaning area is solvent refined coal. This is an example where a good deal of private sector leadership has been taken, but the pins have been pulled out from under it at a very late stage of development and demonstration because of the backing away of Federal funding.

Now whether that will ever be restored through the Synthetic Fuels Corporation or other source is of course up in the air right now, but it is certainly stalled at this point.

Mr. ERTEL. It seems that we are all sitting here flailing a dead horse. We seem to be in agreement as to what the problem is, one of the problems is that the Federal Government is withdrawing almost entirely from development and research into the fossil fuel areas, many of the areas that you consider to be crucial.

It seems to me that you are preaching to the choir here. The question is, how do you preach somewhere else to restore some of those funds? Otherwise, we seem to be dead in the water. Now how do you do that? I guess that is a political question.

Mr. YEAGER. Yes; it is.

Mr. ERTEL. If you can figure out an answer to that you can tell me privately.

Mr. ANTHONY. We certainly will be doing it, Mr. Chairman. We think it is important enough, we will be doing it.

Mr. ERTEL. I think basically you have answered most of the questions I have. I can anticipate your answers on the others based upon what you have said so far. If I have any others—does any of the staff have any questions?

Thank you very much for participating, enlightening us with your viewpoint. We hope that enlightened viewpoint gets communicated.

[Whereupon, at 4:35 p.m., the subcommittee adjourned.]

APPENDIX I



OTISCA INDUSTRIES, LTD.

P.O. BOX 127 SALINA STATION SYRACUSE, N.Y. 13208 315/475-5543 R&D 412/947-3877

STATEMENT

OF

OTISCA INDUSTRIES, LTD.

for the

Energy & Development & Applications Subcommittee

Of the

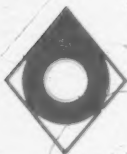
House Science & Technology Committee

Regarding Hearings on the Direct Combustion

Of Coal

December 10, 1981

(75)



OTISCA INDUSTRIES, LTD.

P.O. BOX 127 SALINA STATION SYRACUSE, N.Y. 13208 315/475-5543 R&D 412/947-3877

STATEMENT OF OTISCA INDUSTRIES, LTD.

Because the United States has 31 percent of the world's economically recoverable coal reserves, coal development is increasingly seen as a means of reducing our nation's dependence on foreign oil and gas. The Powerplant and Industrial Fuel Use Act of 1978, for example, articulates a Congressional policy "to encourage and foster" the greater use of coal as a primary energy source in lieu of natural gas and petroleum. ^{1/} The Act also states, however, that our nation's air quality goals are not to be sacrificed to meet this objective. ^{2/} In fact, there is considerable concern that greater reliance on coal may result in additional atmospheric pollution unless appropriate preventative steps are taken.

Otisca Industries, Ltd., a New York-based company employing 31 persons, has patented and developed pollution control systems which will enable the nation to resolve these competing concerns. Two of these systems -- the Otisca Process and the T-Process -- are among the most efficient methods for cleaning pyritic sulfur and fly ash from coal.

As will be explained below, Otisca has virtually completed a contract with a major Midwest utility for the construction of a 125 ton per hour plant for processing coal at one of its electrical power-generating facilities. In addition, Otisca has developed in a joint venture with another utility a processed coal that can be used as a direct replacement for No. 6 fuel oil. T-Coal is also used as a fuel in GM's new coal-powered Cadillac-El Dorado. ^{3/}

The Importance of Clean Coal

Reducing sulfur dioxide and particulate emissions of coal-fired power plants has long been one of the cornerstones of our

^{1/} 42 U.S.C. § 8301.

^{2/} 42 U.S.C. § 8471.

^{3/} New York Times, D-4, June 4, 1981.

nation's environmental policy. For example, the Environmental Protection Agency in June 1979 issued New Source Performance Standards requiring the continuous removal of up to 90 percent of the potential combustion concentration of SO_2 from boiler flue gases of power plants constructed since September 18, 1978. Except for some of the very low sulfur coals and lignites, however, practically no U.S. coals can meet these standards without some form of pre-combustion or post-combustion sulfur control. At the same time, domestic coal consumption is expected to increase from the 620 million tons burned in 1977 to 1144 million tons by 1990, and by even greater amounts in other countries. 4/ Because this sharply increased use of coal may lead to greater generation of air pollutants, it is likely that there will be strong demands for improved coal cleaning technologies. In fact, the Congressional Research Service reports that the plentiful supply of high-sulfur coals such as those found in the U.S. Eastern Interior Basin will be competitive in foreign markets only if ways can be found to clean it before shipping. 5/

Laying aside the environmental problems, it has long been assumed that the burning of "dirty" coal adversely affects the boilers of coal burning plants. A study of five TVA plants by the Department of Energy recently confirmed these assumptions, finding a direct correlation between coal quality and boiler maintenance to the extent that each percentage reduction in the ash and/or sulfur content proportionately reduced boiler maintenance costs. 6/ The study provides a clear example of the direct costs incurred when pollutants are not removed from coal.

According to one industry expert, beneficiation, or physical coal cleaning, is a "proven and cost-effective technology for removing pyritic sulfur and ash-forming minerals from raw coal before combustion." 7/ He points out that when used in conjunction with flue-gas desulfurization, beneficiated coal "can substantially reduce the level of continuous sulfur dioxide

-
- 4/ The Energy Factbook, Committee on Interstate & Foreign Commerce, United States House of Representatives, 96th Cong., 2d Sess., 560 (1980).
 - 5/ Congressional Research Service, Factors affecting the Export of High-Sulfur Coal from the Eastern Interior Basin, Cmte. on Governmental Affairs, United States Senate (1981).
 - 6/ Effect of Coal Quality on Maintenance Costs at Utility Plants DOE/ET/12512-1, U.S. Dept. of Energy (1980).
 - 7/ Roman, Beneficiation: An Alternative to 100 Percent Flue Gas Scrubbing, Coal Mining & Processing, 68 (September, 1980).

removal that an FGD system must contend with, and at less cost than the FGD capacity which it replaces." 8/

Cleaning Coal Using The Otisca Process

The Otisca Process beneficiates coal in the following manner. Raw coal from the mine is placed in a bath of heavy organic liquid, the density of which is about 1.50 gms/cm³. The bath forces the less dense coal to float, making it easily removable from the surface. The more dense gangue or refuse material, i.e., mineral matter including sulfur compounds, sinks and is recovered separately. When used for steam generation, cleaned coal recovered from the Process can in many cases meet EPA's clean air standards for new boilers and, in the other cases, dramatically reduce the sulfur and ash load to the after-burner scrubbers.

There are several other types of coal cleaning techniques currently in commercial use (e.g., hydrobeneficiation, air separation, jigging, froth flotation, cycloning and shaking on Deister tables) but none is as efficient and economical as the Otisca Process for fine coal cleaning. Conventional hydrobeneficiation facilities, for example, are now used to clean a very large fraction of the coal mined in the United States today (600 X 10⁶ tons produced per year). In comparative tests, however, Otisca-cleaned coal has not only been found to result in higher BTU yields, it also produces far less sludge and boiler refuse when combusted. At the same time, it extracts more pyritic sulfur than can be accomplished through water cleaning alone. As a result, the more efficient extraction of mineral matter by the Otisca Process reduces the load on scrubbers, electric precipitators and power plant fly ash disposal facilities.

Further, because the Process is self-contained, it avoids several environmental penalties associated with conventional hydrobeneficiation. While the hallmark of these facilities is the discharge of large volumes of contaminated "black water" into settling ponds, the Otisca Process is characterized by ultra-efficient recovery and recycling techniques, allowing nothing ecologically detrimental to be discharged.

Equally important, in many cases Otisca Processed coal is cleaned at a cost well below that of hydrobeneficiated coal. In fact, if EPA were to tighten its water pollution rules relative to hydrobeneficiation facilities as has been proposed at 46 Fed. Reg. 3136 (1981), this cost differential is likely to increase in view of the capital investment required to achieve compliance.

Also, hydrobeneficiation processes typically require substantially more energy than the Otisca Process to clean equivalent amounts of coal. Because of the many advantages of the Otisca Process, it has the potential of making a significant contribution to our nation's environmental program at a time when far greater demands are being placed on coal for power generation.

Cleaning Coal Using the T-Process

Otisca's T-Process is an advanced coal beneficiation technology which refines coal to ultra-low ash levels to achieve a product comparable to No. 6 fuel oil. Under this patented process, raw coal is milled in a solution of water and other milling aids to an average particle size of 2/10,000ths of an inch, separated from its impurities and washed. The final product is shipped as a powder or a slurry to the consumer. The Process is expected to be in pilot plant operations early next year at which time full details of the economics will be available. Preliminary studies, however, indicate that T-Coal should cost approximately \$2 per million BTUs as compared with No. 6 fuel oil's present price of \$6.50 per million BTUs.

In addition to the economic factors, one of the most encouraging characteristics of T-Coal is its compatibility with existing oil-designed utility plants. Historically, coal has been the principal utility fuel. In the 1960s, however, utilities began switching to oil and natural gas, primarily because of economic considerations and the need to meet new environmental regulations for allowable air pollutant emissions. As a result, new plants were designed to burn either oil and gas as their primary fuel and some existing coal designed plants were converted to use oil-fired boilers.

Recently, this trend began to reverse itself. The dramatic increase in oil prices and the lack of secure sources of supply has encouraged a return of some plants to a coal-designed status. Also, the 1978 Power Plant and Industrial Fuel Use Act precludes the construction of new baseload power plants capable of burning only oil or natural gas and eliminates the use of natural gas in existing power plants after 1990.

The utility industry, however, cannot convert existing oil-designed plants to take advantage of plentiful coal supplies without severe plant derating and significant operating problems. Such plants typically have small furnaces, narrow tube spacings and flat bottoms. Because they were designed to burn only oil or gas, use of superior quality coal is essential if utilities are to maintain operating efficiencies and avoid large capital investments during conversion. T-Coal's ultra low ash and attractive BTU yield properties suggest its potential for use in these conversions.

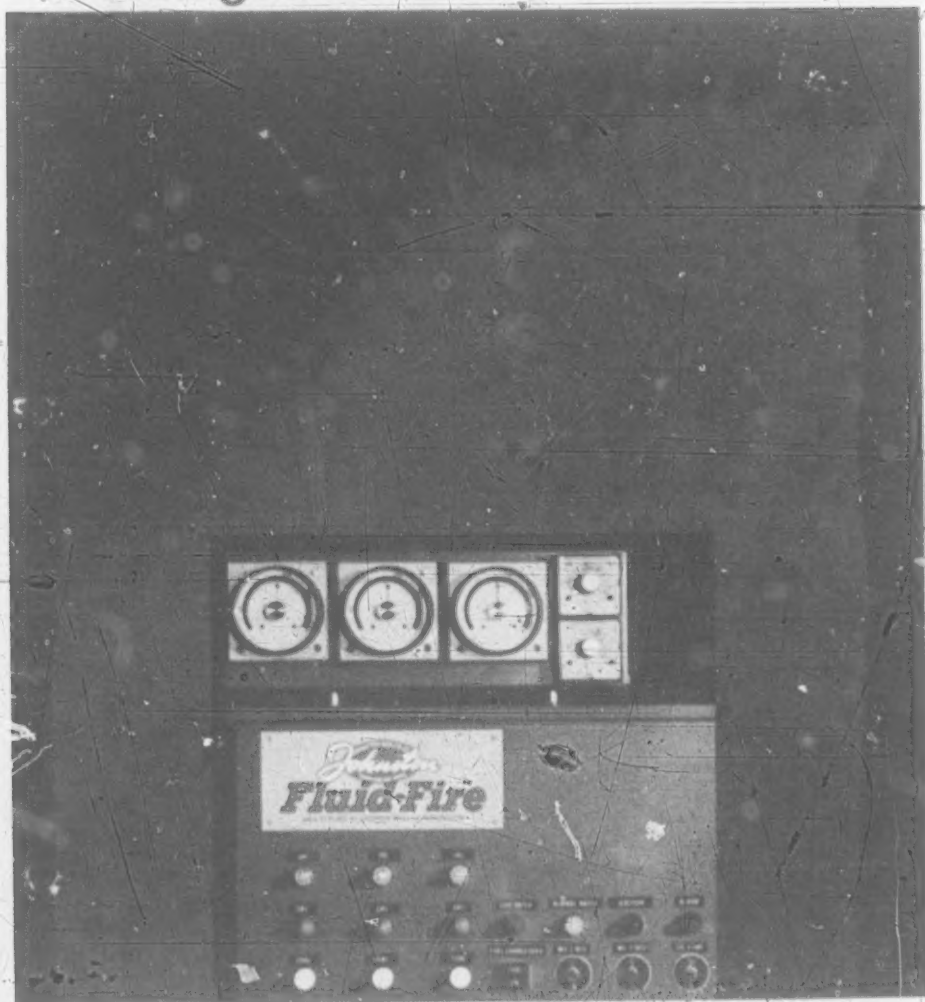
T-Coal has also been successfully tested by General Motors in a Cadillac El Dorado powered by a gas turbine engine converted to burn coal. Such engines require relatively clean hydrocarbon fuels which can be suitably dispersed in the heating chambers. Earlier tests with powdered coal having a two percent or greater ash content indicated that the ash particles caused severe turbine wear and emission problems, thus making such coals impractical. Because the ash content of T-Coal is substantially less than one percent, it can replace fuel oil directly without major equipment modifications.

Conclusion

There has been some hesitancy to take advantage of our nation's immense coal reserves because of environmental concerns. With emerging technologies such as those developed by Otisca Industries, however, our energy demands no longer need to be supplied primarily from foreign sources.

APPENDIX II

**Johnston
Multi-Fuel
Fluidized Bed Combustion
Packaged Boilers**



(81)

Fuel flexibility is essential for commercial and industrial energy users

As a result of the many economic and political uncertainties surrounding both the availability and cost of energy, fuel flexibility is absolutely essential to the continued growth and economic stability of industry. More and more enlightened energy managers are evaluating alternative fuels as a solution to their own as well as our nation's energy crisis.

Coal, with its great abundance in the United States, will by necessity become a major alternative to natural gas and oil. Over 3,224 billion tons in USA coal deposits greatly surpass the combined known resources of all other fossil fuels. However, the renewed use of coal, particularly high ash-high sulfur coal, has environmental characteristics which currently restrict its use. Environmental standards for coal fired boilers are becoming more stringent at the very time our government is calling for massive conversion to coal. In addition, current coal combustion technology does not satisfy today's need to burn various types of coals as well as gas or oil in a single unit.

New technology is needed to provide the commercial and industrial energy user with a truly "multi-fuel" boiler capable of utilizing coal, of varying characteristics, as well as gas and oil. Further, this new "multi-fuel" boiler must be able to burn these fuels both efficiently and cleanly to meet not only today's standards but also those standards which can be reasonably forecast in the future.

Environmental emission standards for commercial and industrial boilers can be expected to become more stringent in allowable emissions of sulfur oxides, nitrogen oxides and particulates.

Future standards can be predicted by the current standards in force for large industrial and utility size boilers. Proposed legislation would also force these standards on smaller industrial and commercial boiler users.

Ironically, as environmental emission standards become more stringent, further legislation appears imminent which would force many

commercial and industrial users to convert from gas and oil to coal or other solid fuels.

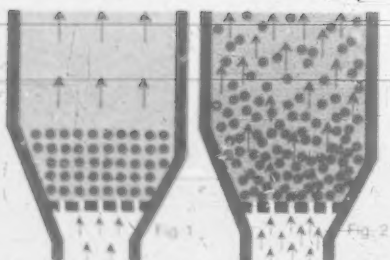
Fluidized Bed Combustion is the solution

The solution to this need for multi-fuel boilers capable of clean and efficient combustion of coals, oil and gas is found in a technology called "Fluidized Bed Combustion." Johnston Boiler Company, an industry leader since 1864, has again taken a leadership role in the development and commercialization of this new technology.

Working under a technology and patent license with Combustion Systems Limited of the United Kingdom, Johnston has developed a multi-fuel Fluidized Bed Combustion packaged boiler. This revolutionary new product burns all grades of coal regardless of sulfur or ash content as well as all grades of oil and natural gas, either individually or simultaneously. It does so with improved combustion efficiency and emission performance which meets the most stringent current or proposed EPA standards.



Combustion Systems Limited is a company formed jointly by three United Kingdom organizations: the National Coal Board, British Petroleum Ltd. and the National Research Development Corporation, to develop fluidized combustion technology throughout the world. Extensive research and development programs carried out at facilities associated with CST have resulted in a major resource of "fluidized combustion know-how". Shown above is an aerial view of the National Coal Board Research Establishment at Stoke Orchard where much of the development of fluidized combustion technology has taken place.



How fluidized combustion works

In fluidized combustion, fuel is injected and burned in a "fluidized bed" of particles of fuel or matter (ash, limestone or sand). Water-cooled heat-transfer tubes located within the bed and surrounding water-wall surfaces maintain an optimum temperature for heat transfer and sulfur reduction.

As shown in Figure 1, when a bed of inert material is subjected to an evenly distributed flow of air, the material is forced upward and suspended in the gas stream. As the velocity of the gas is increased (Figure 2), the bed becomes highly turbulent and rapid mixing of the particles occurs. The surface is no longer well defined but appears diffuse, and bubbles of "gas" similar to those formed in a boiling liquid rise through the bed. A bed in this state is said to be fluidized; it behaves as a liquid, finding its own level and possessing hydrostatic head.

The advantages

The characteristics of fluidized combustion enable solid, liquid and gaseous fuels to be burned cleanly and efficiently regardless of sulfur or ash content. Fluidized combustion permits high-intensity combustion while reducing the emission of sulfur dioxide and nitrogen oxides to levels below the most stringent standards either in force or proposed in the United States. Sulfur reduction is accomplished by adding limestone or dolomite to the fluid bed, resulting in sulfur capture in the form of a calcium sulfate ash. Thus, fluidized combustion eliminates the need for expensive high-maintenance flue gas scrubbers.

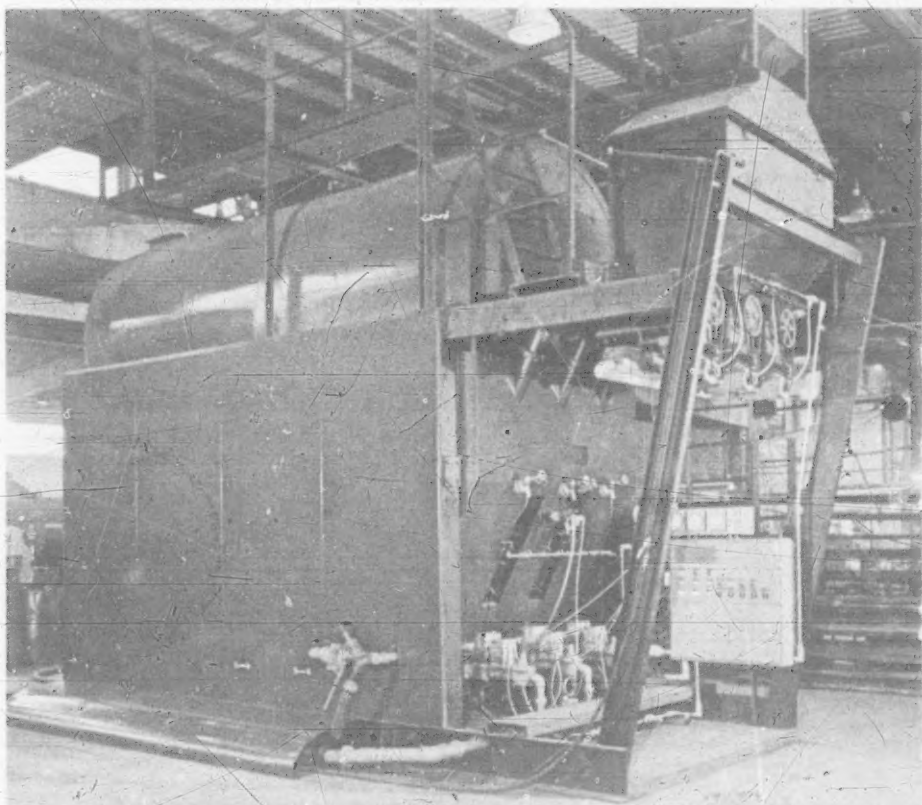
Low combustion temperatures (approximately 1600 F) from effective radiant heat transfer surfaces within the bed permits a large reduction in the total heat transfer surface, resulting in an overall cost savings. Of great importance is the ability to produce shop-assembled, packaged, multi-fuel boilers, with their inherent cost savings compared to field erected or field assembled units.



Advanced Fluidized Bed Combustion Demonstration in Action

Johnston Fluid-Fire Series

Fluidized Bed Combustion Steam and Hot Water Boilers



Design Parameters

Output: 2000 to 50,000 lbs/hr

Design pressures: 150 to 1,000 psi

Fuels: All grades of coal

Wood and wood wastes

Slag and cinders

Peat, Fuel oil and Waste oil

Natural gas and Propane

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Oil shale and Lignite

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

Johnston Fluid-Fire Model 2000 Gas Output: 1,000,000

750 lbs/hr installed at Johnston Company in New York, N.Y.

NOISE LEVEL: 85 DBA @ 100 FT

Greater fuel flexibility

Johnston's Fluid-Fire Series accommodates all types of coal #2-#6 and natural gas either individually or simultaneously. Actually, the unit burns almost any liquid, gaseous or solid combustible product. A flow of a mixture instantaneously switches from one fuel to another.

pulverized or crushed coal — not required since the Johnston Fluid-Fire Series utilizes conventional stoker coal with a bit less than 1% A fluid fire unit may be installed today. In the future, it may be easily and economically converted to gas firing by adding material handling equipment when fuel prices and availability make it necessary.

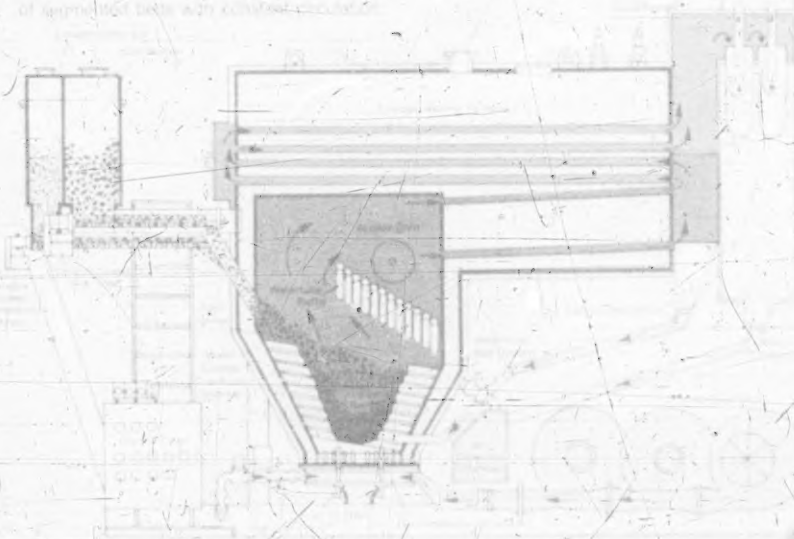
Dependable performance

The Johnston Fluid-Fire Series responds to load and changes by utilizing a new system of regulated beds with constant recirculation.

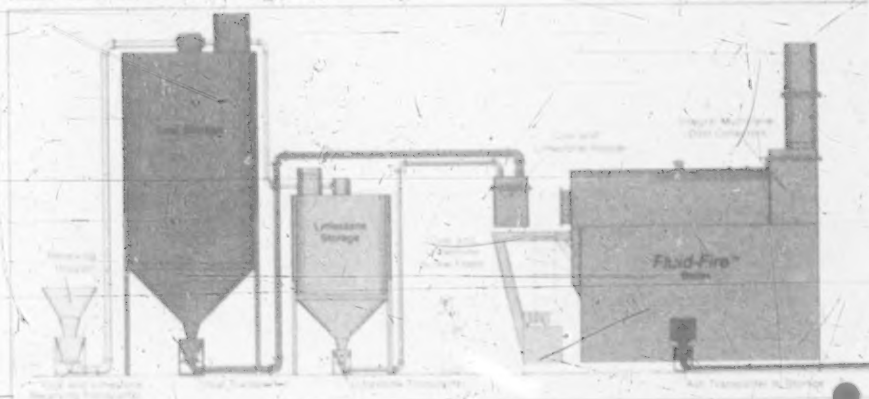
This provides all the right when firing all fuels. Johnston's Fluid-Fire Series is designed to meet the standards of the Fluid-Fire Series by using a one standard — an action. With Johnston's Fluid-Fire Series, the only standard is the standard of the Fluid-Fire Series. The Johnston Fluid-Fire Series is designed to meet the standards of the Fluid-Fire Series. The Johnston Fluid-Fire Series is designed to meet the standards of the Fluid-Fire Series. The Johnston Fluid-Fire Series is designed to meet the standards of the Fluid-Fire Series.

Superior efficiency

With the Johnston Fluid-Fire Series, the only standard is the standard of the Fluid-Fire Series. The Johnston Fluid-Fire Series is designed to meet the standards of the Fluid-Fire Series. The Johnston Fluid-Fire Series is designed to meet the standards of the Fluid-Fire Series. The Johnston Fluid-Fire Series is designed to meet the standards of the Fluid-Fire Series.



Gas, Oil & Coal A multi-fuel boiler system ...at an affordable price



equivalent or superior in station to packaged fire tube or watertube boilers.

The Johnston Fluid-Fire® boiler uniquely prevents combustion loss and reduces radiation and convection heat losses, further improving fuel-to-steam boiler efficiency.

In all cases, Johnston provides a "Certified Boiler Efficiency Certificate," which assures the owner of the highest possible efficiency. See the Johnston-Certified Boiler Efficiency Manual for further details.

Lower initial cost

This new technology dramatically reduces the initial capital cost of coal and multi-fuel boilers. Cost comparisons indicate savings from 10-25% or greater can be realized, compared to traditional stoker fired coal or oil fuel boilers. For applications where sulfur dioxide emission control is necessary, the fluidized bed combustion process with SO_2 retention eliminates the need to purchase expensive scrubber equipment and also greatly reduces water operating costs. In this case, cost reductions of 50% or greater can be achieved. These reductions include the cost of limestone storage and the handling and feeding costs applicable to the fluidized bed combustion process.

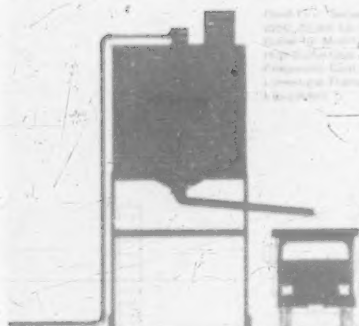
Lower installed cost

The Johnston Fluid-Fire® Series is a packaged boiler with all fuel train components, combustion equipment, and forced draft fans piped and wired in a shop assembled unit. Field work is limited to connection of coal transport belt removal, auxiliary fuel connection and electrical power. The package boiler design not only cuts installation cost, but also eliminates the need for mezzanines, basements, air hoppers, and remote mounted dust collectors.

Lower operating cost

Installation, operating and maintenance cost savings are another benefit of the Johnston Fluid-Fire® Series. Refractory, a significant installation and perpetual maintenance problem in traditional stoker fired boilers, has been eliminated completely. All combustion surfaces are 100% water cooled for a long maintenance free life. Unlike the problem associated with traditional water tube boilers taking inner and outer casings, there is no casing corrosion in the Fluid-Fire® Series.

The Fluid-Fire® Series is designed for automatic operation while firing gas or oil and



But basic best designs of the *Flint Fire*

Johnston Boiler Company
 Ferrysburg, Michigan 49409
 Phone (616) 842-5020 Telex 726-406

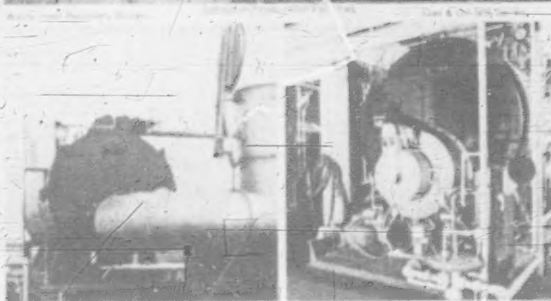
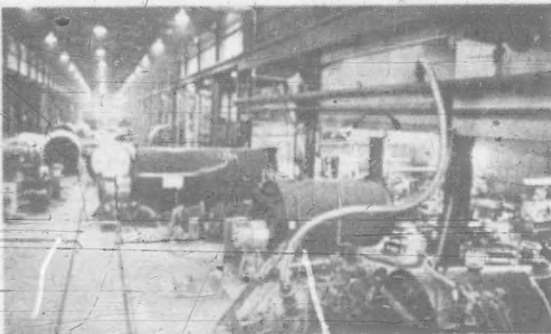
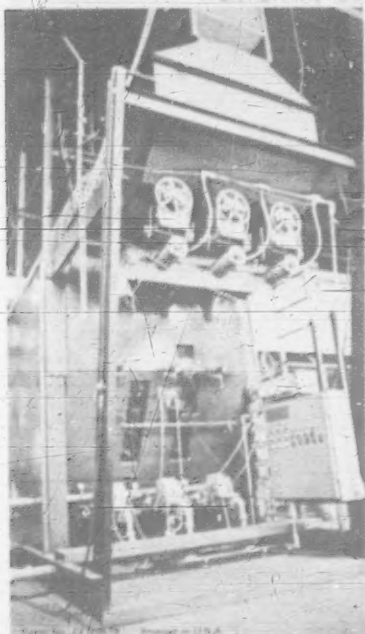
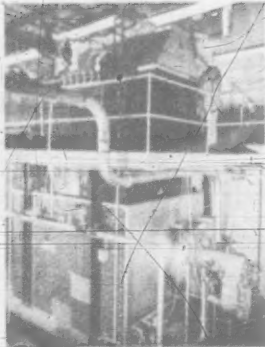
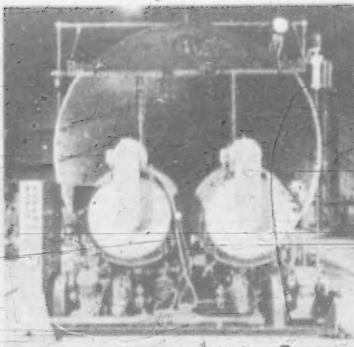
The Johnson story

Johnson Pump's success is evidence of long lived pump designs. They have a long record in factor test ratings for commercial industrial and marine applications. Established in 1904,

Johnson Pump's reputation for reliability and performance has made it a leader in the pump industry.

up to 70,000 gph for commercial, industrial and marine applications.

Product quality, flexibility and fast lead times have resulted in Johnson Pump being one of the country's fastest growing pump manufacturers.



FLUIDIZED BED COMBUSTION INSTALLATIONS

By John Wallish

The often confusing and complex matrix of energy management solutions has been answered for industrial and commercial energy users, with the use of fluidized bed combustion packaged Fluidfire boilers as manufactured by Johnston Boiler Company of Ferrysburg, Michigan.

Fluidized bed combustion boilers possess superior advantages over conventional solid fuel firing methods. The major advantages of fluidized bed combustion packaged boilers over conventional stoker fired boilers are as follows:

- * Greater fuel flexibility
- * Packaged type design
- * Lower emissions
- * Lower initial, operating and maintenance costs

The product line of Johnston Fluidfire fluidized bed combustion boilers has received rapid and wide acceptance through-out the industrial and commercial market. Twenty-one boilers have been ordered to date that range from 2,500 lbs./hr. to 50,000 lbs./hr. for various process and heating requirements.

Fuel Flexibility

The industrial and commercial energy user now has a choice, based on their local economic and supply situation, of the type of fuel to use without expensive retrofit or replacement of existing boiler equipment, when a Johnston Fluidfire fluidized bed boiler is installed.

The fuel "coal" has been the preferred primary fuel with gas and oil as secondary fuels in most of the installations.

Fluidized bed combustion boilers offer a new dimension to true flexibility. A wide variety of coals have been successfully fired in these boilers. The extremes of the analyses of coals fired to date have varied in high heat value from 5,386 BTU/Lb. to 14,000 BTU/Lb., sulfur content from .62 to 6.0%, ash content from 2.6% to 51.62%, and top sizes up to 2" with 100% fines.

In addition to conventional fuels such as natural gas, propane, #2 and #6 oil, a number of other fuels have been successfully burned. A few of these fuels are as follows: anthracite culm, wood chips, pelletized wood and paper waste, alcohol, shingle scraps, bituminous coal fines (size 1/8" x 0), and food processing waste sludge.

Packaged Type Design

The packaged type design of the fluidized bed boiler significantly reduces field assembly and erection time to a minimum, and therefore shortens plant start-up and operation. It has also been determined that multiple unit installations are lower in cost than one large field erection conventional stoker fired boiler.

Emissions

One of the major advantages fluidized bed combustion boilers offer, is the control of SO_2 emissions without the use of wet or dry scrubbers. Feeding limestone into the bed when burning coal or high sulfur #6 oil reduces SO_2 emissions to acceptable levels in most cases. The end product is a dry stable material that is readily acceptable at landfills. The costly expense of operating and maintaining scrubbers and using settling ponds is eliminated.

Oxides of nitrogen reduction is accomplished by the low (1600°F) temperature of the bed.

Particulate emissions are controlled with the use of conventional (cyclones and baghouse) dust control equipment.

Cost

The fluidized bed boiler is a packaged type unit, which results in lower installation costs. There is no refractory in the firetube type boiler thereby eliminating the maintenance requirement that is common to conventional brick set boilers.

Not only is the refractory an expensive maintenance item, but more importantly reduces fuel-to-steam efficiency due to high radiation and convection heat losses.

Fuel to steam efficiencies are in most cases greater than conventional coal fired boilers. The fluidized bed boiler operates with 20% to 25% excess air requirements. Certified test results are on the 40,000 lbs./hr. Johnston Fluidfire Fluidized Bed Boiler installed in Marion, Ohio attained an outstanding fuel-to-steam efficiency, burning Ohio bituminous coal with 40% fines, of 83.6%.

Fluidfire Watertube Boilers are also available for applications requiring steam pressures in excess of 300 psi.

Installations

The 10,000 lbs./hr. fluidized bed boiler (Fig. 1) in Johnston Boiler Company's factory in Ferrysburg, Michigan has been in operation for over four years. The advantages of fluidized bed combustion have been demonstrated to over 3,000 people who have witnessed the operation. This boiler has burned all the fuels listed above plus other wastes too numerous to mention.

The first of 20 fluidized bed boilers purchased from Johnston, as shown in Figure 2, has been operating since April, 1980. The 40,000 lbs./hr. capacity boiler produces dry saturated steam at 150 psig for processing soy beans. The boiler is in operation 24 hours a day, 7 days a week, with a scheduled two week plant shut-down a year. The operation of this boiler clearly indicates that fluidized bed combustion boilers provide reliable, efficient and environmentally acceptable performance for industrial applications.

The second fluidized bed boiler purchased is a 20,000 lbs./hr. unit (Fig. 3) installed and operating in Charlotte, North Carolina. This unit was purchased to burn natural gas, #2 oil and #6 oil. The boiler has the capacity to be easily converted to coal once the owner provides the necessary coal and limestone handling system to the boiler. Johnston provided a customer witnessed factory fire test of this unit that clearly indicated fuel to steam efficiencies comparable to conventional firetube or watertube boilers, and controlled SO_2 emissions within acceptable limits when burning coal and #6 oil.

Three (3), 25,000 lbs./hr. Johnston fluidized bed boilers are installed and operating in the country of Brazil for Souza Cruz Industria E. Comercio. These units burn alcohol and Brazilian coal which is 5,300 BTU/Lb., 50% ash and 50% fines. They are also using limestone to control SO_2 emissions. These boilers clearly indicate that fluidized bed combustion boilers can cleanly and efficiently burn low quality fuels without any major modifications to the boiler equipment.

Figure 4 is a 2,500 lbs./hr. fluidized bed boiler installed and operating in Indiana for a small wood working factory. This boiler is the only source of heat during the winter months, which is evidence of reliability of these boilers.

In addition to the 2,500 lbs./hr. boiler described above, two (2) 2,500,000 BTU/hr. hot water boilers are installed and operating in Indiana for a secondary school system. These two boilers burn locally available Indiana bituminous coal. Simplicity of operation is quite evident and once again these boilers are the only source of hot water for heating the school.

One of the most significant orders for fluidized bed combustion boilers was received from a major food processing company that purchased seven (7) 50,000 lbs./hr. Johnston Fluidfire boilers for three of their plant locations.

The first (Fig. 5) three of seven have been manufactured and installed in Ohio. They are scheduled for start-up in December of this year. They are arranged to burn high sulfur Ohio bituminous coal with limestone for SO_2 control, natural gas, and #2 oil. In addition to the above mentioned conventional fuels, the boilers have been arranged to burn a wide variety of food processing wastes, one of which is lacquer. These three units will replace two (2) 75,000 lbs./hr. oil fired watertube boilers. Three packaged boilers were purchased on an economic basis, in lieu of one large field erected boiler.

The next three of seven boilers will be installed in North Carolina for a new multi-million-dollar food processing plant. The first of these three boilers is on the job site with start-up scheduled for January of 1982. These three boilers are the only source of steam for the process load and plant heating requirements.

Number seven of seven is scheduled for shipment from Johnston's facility in December with start-up scheduled for February, 1982. This boiler will replace a 50,000 lbs./hr. oil fired boiler in the state of Maryland.

High pressure (greater than 300 psig) with superheat capabilities are provided in a watertube boiler configuration (Fig. 6). This 10,000 lbs./hr. boiler is installed at Hayward Tyler's factory at Keighley in Yorkshire, England. This fluidized bed boiler has been operating for over a year with results similar to the above.

Conclusions

The astute industrial and commercial energy users are converting their facilities to coal at a very rapid pace. Their individual reasons for converting to coal are different in perspective but have the same comparable underlining facts. The two major facts considered are economics and energy independence.

The ground rules of equipment selection include: reliability, flexibility, efficiency, environmental implications, and initial, operating and maintenance costs. The above listed fluidized bed boiler installations are testimony that the boilers they purchased clearly outdistanced other products.

Fluidized bed combustion boilers are a proven, advantageous, alternative for the industrial and commercial energy user.

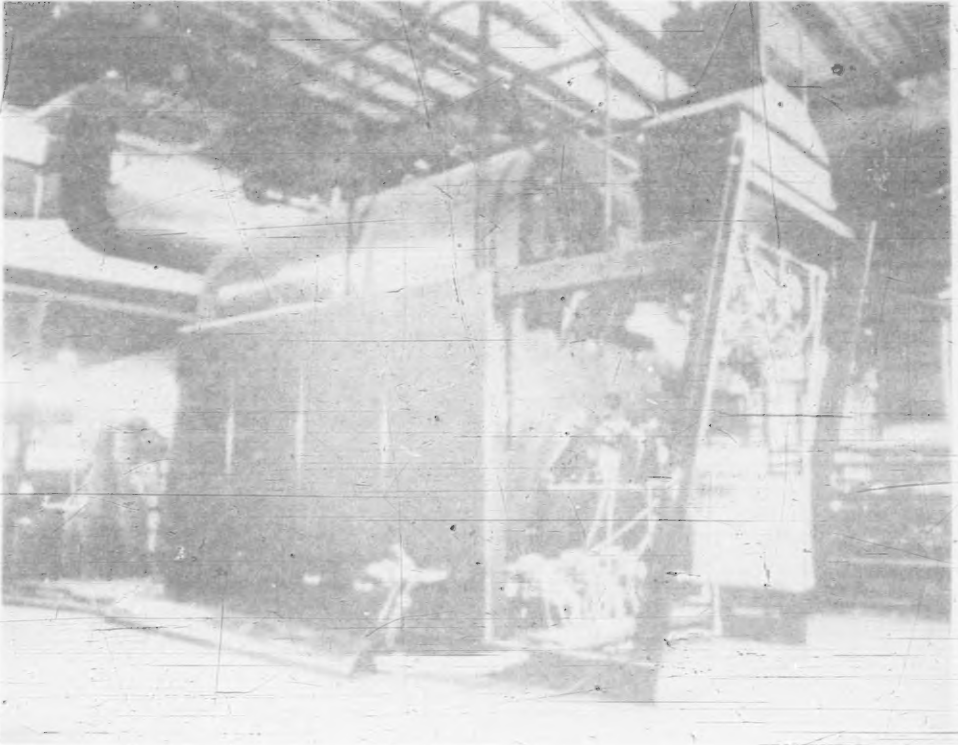


Figure 1.

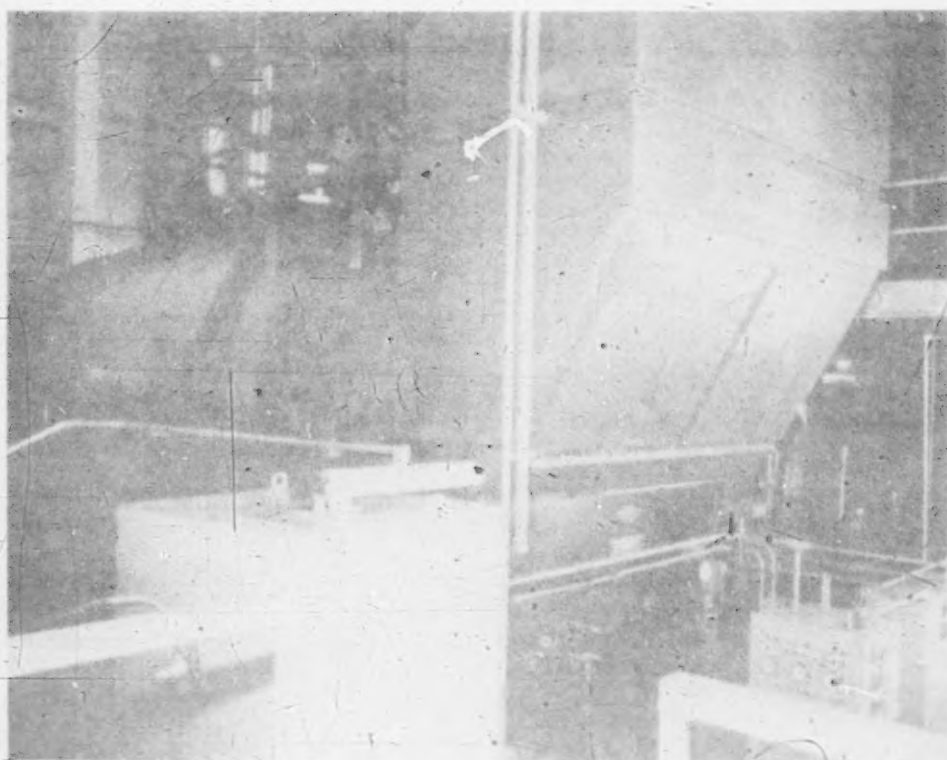


Figure 2.

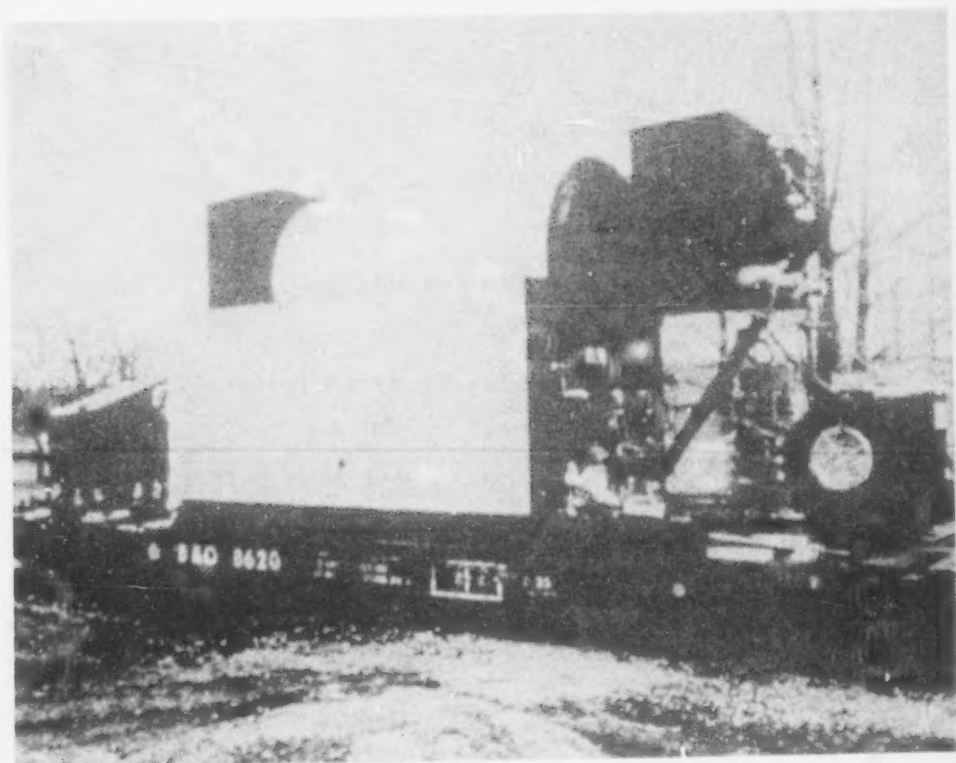


Figure 3.

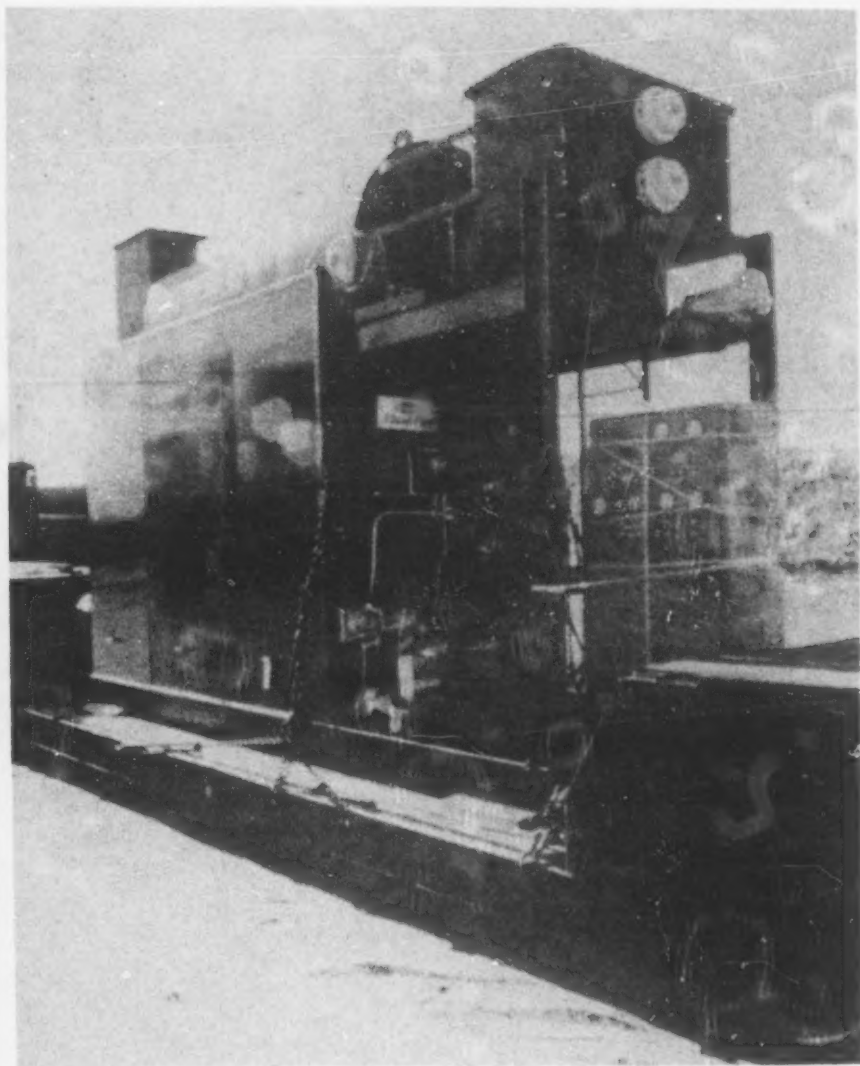


Figure 4.

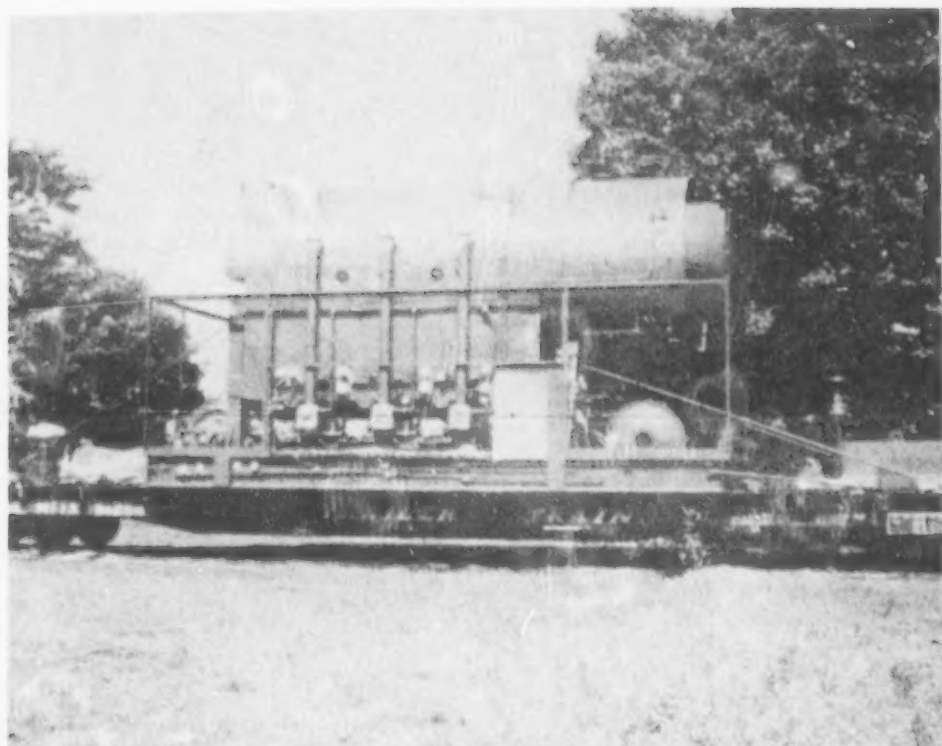


Figure 5.

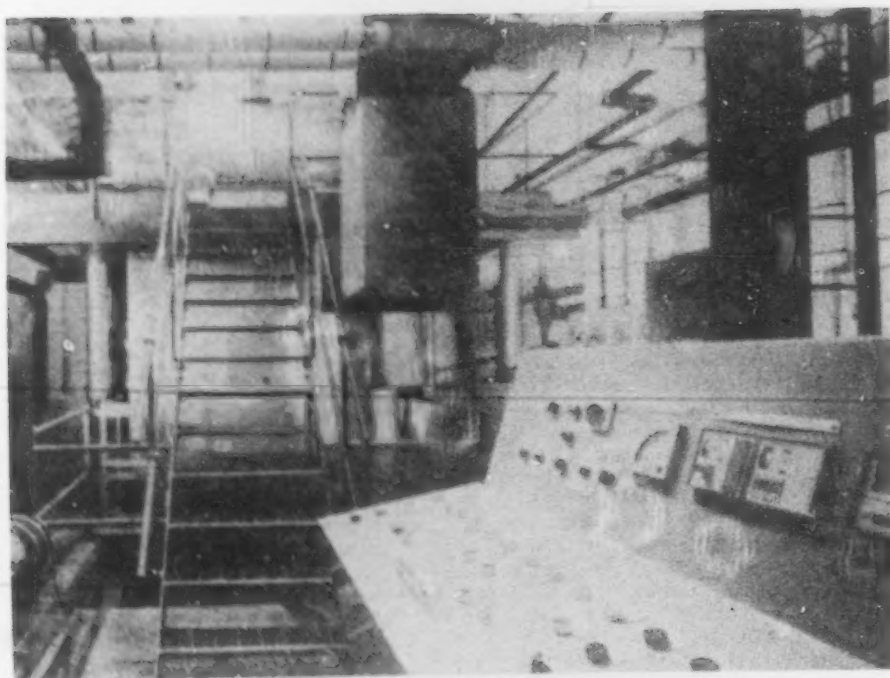


Figure 6.

JOHNSTON BOILER COMPANY

MICHAEL J. VIRR

EXPERIENCE OF INDUSTRIAL FLUIDIZED BED BOILER PLANT

INTRODUCTION

We have been involved in the design and development of industrial fluid bed boilers and furnaces for over ten years and in that time have seen the boiler industry take increasing interest in the technology because of its ability to burn coal efficiently and cleanly - in short, the ability to meet high emission standards on SO_2 and NO_x while maintaining high efficiency.

The approach to fluid bed boiler design for industry is very different from the designs usually put forward for utility boilers because industrial installations must be simple to install and operate on automatic control while having low power consumption. Basic criteria therefore was to adapt the new technology fluidized bed combustion to the traditional concept of the industrial package boiler which is manufactured to a large degree of completion in the boiler plant and shipped to the customer before installing in a relatively short time. This is basically very different from the on-site erection of utility boilers which calls for high degrees of contracting skills in the construction industry.

The "packaging" of the design is achieved by taking a typical solid fuel fire tube boiler or "D" shaped water tube package boiler and adapting the combustion chamber for fluidized bed firing. The advantages of the fluidized bed can be readily utilized because it results in a relatively small combustion chamber with very high heat transfer coefficients that occur within the fluidized bed itself. It is possible for the relatively few "in-bed" tubes to actually generate 50% of the output of the boiler. In this manner a relatively compact shippable boiler design may be achieved, which goes to maximum capacity of 50,000 lb/hr for the Fluidfire fire tube boiler and 70,000 lb/hr for the Fluidfire water tube boiler.

The simplicity of operation is achieved by using the concept of a through bed or in-bed burner for startup using gas (in one case, on alcohol), which eliminates the need for a separate startup burner.

The simplicity of control is achieved by using separation of the fluid beds as heat exchangers and a turndown of three to one can be readily achieved.

A high efficiency of the boiler can be achieved by using the fluidized bed itself to get complete combustion of fines by enveloping the incoming coal in a circulation of hot solids, ensuring that even fine particles are burned. This eliminates the need for a carbon burnup cell and ensures a long residence time and good sulphur retention.

In these days of high standards required by environmental protection agencies, the design from the outset must bear in mind the high degree of emission control that must be achieved.

The sulphur in the coal is retained within the bed by using a particulate bed of limestone which converts the calcium carbonate to calcium sulfate ash which is inert at ambient temperature and has no restrictions in disposal as landfill.

Very low oxides of nitrogen are also achieved compared to conventional boilers because of the low combustion temperature which need not exceed 1650°F. with a resultant NO_x of less than 300 parts per million.

The particulate discharge from the boiler is controlled by the use of multi-cyclone dust collectors followed by a bag house so that the highest standards of particle emission can be achieved. Boilers of the size of 2,500 to 50,000 lb/hr steam are now being produced which give efficiencies over 80% when burning coal. Considerable fuel savings can be made over those plants using conventional coal burning technology.

Both the Fluidfire fire tube and water tube boilers have now been operating in industry for over twelve months. With over ten plants being delivered and operational, considerable confidence can now be shown in the adoption of these new high technology boilers on a normal commercial basis.

THE FLUIDFIRE FIRE TUBE BOILERS

The initial concept envisioned by Johnston was to commercialize a product range of shop assembled, packaged, fire tube boilers capable of multi-fuel firing that could be readily transported by rail, economically installed, and afford stable and efficient operation. Johnston's long experience in solid fuel as well as gas and oil firetube boilers is used in conjunction with the fluidized bed technology developed by Combustion Systems Limited which is the managing agency of a partnership consisting of the UK National Coal Board (NBC) and The British Petroleum Company (BP).

Johnston adopted a design based on their SF series boilers designed for solid fuel as well as gas or oil firing. The combustion chamber of this boiler was extended downward and tapered to form a full water cooled chamber for the fluidized bed that was then divided into three parts by closely pitched bed divider tubes. Distributors were designed which used injection nozzles that could take an air/gas mixture for startup and also incorporated oil/air nozzles making the unit a truly multi-fuel burner. (Fig. 1)

The boiler is started up by initiation of a pilot ignitor which lights the gas/air mixture over the central bed. When the central bed has been established, firing solid fuel, the two side beds may be sequentially started as demanded by the boiler control system based on the steam pressure.

The first unit built was a 10,000 lb/hr boiler operating at about 100 psi and after a year of successful running of that boiler, sales were initiated by an order for a 40,000 lb/hr unit to the Central Soya Company at Marion, Ohio. The successful operation of that boiler has been described by two of that company's engineers in some detail after a year's operation (Ref. 1). The highlights of that report show a boiler efficiency of over 82% while maintaining low NO_x and SO_2 emissions and particulates well within EPA standards. Sales of these boilers have now been achieved in the range of 2,500 to 50,000 lb/hr of some ten units now delivered and operating. Field trials have shown that in all cases these boilers are capable of meeting EPA regulations and maintaining a very high efficiency. Fuel savings alone can fully justify the installation of the new technology boilers and a further paper is available describing the technical performance in more detail from Central Soya engineers.

Johnston Boiler Company is currently building seven 50,000 lb/hr boilers (six now supplied) for a major food company to supply process steam at 150 - 300 psig.

The boilers are for three facilities, three units at Napoleon, Ohio where they will replace two 75,000 lb/hr oil-fired boilers; Maxton, North Carolina where three boilers are the only steam supply in a completely new multi-million dollar food processing plant; and Salisbury, Maryland where the FBC unit replaces an existing 50,000 lb/hr oil-fired boiler (see Photo 2).

THE FLUID FIRE WATER TUBE BOILER

The general arrangement of the Fluidfire package water tube boiler design is shown in Fig. 3 and is based on the traditional "D" shaped water tube package boiler of which many thousands have been built for gas and oil firing. This design differs from the traditional concept by the incorporation of the patented fluidfire concave bed within the combustion chamber where the shape induces the fluidized solids to flow down in the center, returning to the surface at the sides.

The fuel is delivered below the surface in the center of the bed so that the hot downward moving solids envelop the fresh solid fuel and cause it to circulate. The resulting substantial residence time for fuel particles below the surface is sufficient to achieve high combustion burnout efficiencies and thus prevent the carryover of unburnt fuel to the cyclone. This eliminates the need for the "burnout cell" normally required for large flat bottomed fluid beds typical of utility boiler designs, making this new FBC boiler more simple in design and more economical to manufacture.

The unit is designed with over six feet of freeboard within the combustion chamber thus allowing volatiles to burn out completely before entering the convection surface. In the event of high sulphur coals being burned, a dolomite or limestone feed may be incorporated in order to achieve an 80 to 90 percent absorption within the body of the fluid bed. This causes the formation of inert calcium sulfate in the ash which is taken out automatically through the de-ashing system below the bed, and lowers the sulphur dioxide requirements. The long residence time within the bed greatly helps this absorption process.

The water tube boiler is especially designed to achieve natural circulation through both the primary heating surfaces in the combustion chamber which are in the form of nose tubes on each side of the bed and the secondary convection surface between the drums at the back end of the boiler. In the power version of the boilers requiring superheat, a convective superheater replaces the first four tubes in the convective bank of the boiler.

A further Fluidfire design feature deals with high ash coals and industrial refuse containing stone or other tramp materials which do not fluidize when they enter the bed. These fall into a de-ashing trough in the bottom of the furnace which is occasionally fluidized, causing heavy waste material to pass through a large ash valve and water cooled screw at the base of the boiler. This process may be carried out while the unit is in operation and

the stone or tramp material is extracted by water cooled screw feeders. The resulting boiler unit (Fig. 4) is a complete package of some 15 feet high by 12½ feet wide that can be made in the factory and transported by road. Sizes range of the units from 10,000 to 70,000 lb/hr which are some 8 and 34 feet long respectively.

The boiler has an automatic startup control system whereby gas lit from pilot burners combusts within the bed itself. The gas enters the bed through the pre-mix burners which form the distributors for the combustor. These burners may be used for auxiliary firing if very low calorific fuels are used and can be adjusted to maintain boiler output.

One of these boilers has been installed at the Hayward Tyler factory at Keighley in Yorkshire in England and is shown in Fig. 5. This unit is of 10,000 lb/hr capacity and includes a 50-ton coal hopper which is pneumatically fed from the coal truck and an automatic feeding arrangement to the buffer hoppers on each side of the boiler.

The boiler incorporates the ashing-out system mentioned above and a bed ash hopper collects stone and tramp material below the bed from where it can be pneumatically conveyed to a sealed skip in the yard. This same skip is fed with the ash extracted from the cyclone ash hopper on the back end of the boiler that is normally designed to contain a one-month supply of ash. This skip is then removed once per month and includes the calcium sulfate that comes off in the ash. This mixture is disposed of at a convenient landfill site, being basically inert at ambient temperatures.

Figure 6 shows the completed installation. The unit was installed in April 1980. It has now completed its first heating season and is ready to start another. It is designed for automatic startup on a time clock and for generally unattended operation. The boiler is inspected once in the morning and once in the evening to make sure that everything is operating well in the plant. In the event of any form of failure of the boiler systems, an alarm sounds on the control panel and in the main part of the factory. The system is engineered so that part of the boiler will be shut down to a safe condition and an indicator shows where the fault lies. This boiler installation has achieved 97% availability during 1980/81 winter having only two automatic shutdowns during the period, both being caused by adjustment of peripheral equipment rather than for the FBC boiler itself.

Full boiler tests have indicated that a boiler efficiency of 80% is achieved on full load (the boiler is not fitted with an economizer) where the carbon in ash loss is in the order of 5% or below. The boiler has achieved a turn-down of 3:1 on automatic control and 4:1 under manual control. The load following response is excellent, the boiler having picked up loads of 30% virtually instantaneously due to the "flywheel" effect of the red hot fluid bed which stores heat which is immediately available. As the excess air is kept relatively low (typically 20%) at part load, excellent part load efficiency is achieved and figures as high as 79% have been confirmed during testing at half load.

CONCLUSIONS

The rapid acceptance over the last two years of the Fluidfire FBC boiler has been indicated with some 23 units on order; their acceptance in the normal American market is now proven. It is indicative of the acceptance of this type of technology where the supply of fuels has become difficult and people want some insurance against lack of supply of any one single fuel, while fully meeting EPA and local authority regulations with regard to emissions.

These units will not only burn high sulphur coal to within EPA standards but also can have separate feeders for conveying of waste material into the fluid bed to be burned as make-up fuel.

The introduction of the Fluidfire water tube boiler is expected to receive similar rapid acceptance having a greater range of industrial uses being adaptable to higher pressures and co-generation schemes.

The USA has the largest reserves of coal in the world and there is no reason why plant managers should have to rely on imported fuels in order to ensure the security of electricity and steam to their plants.

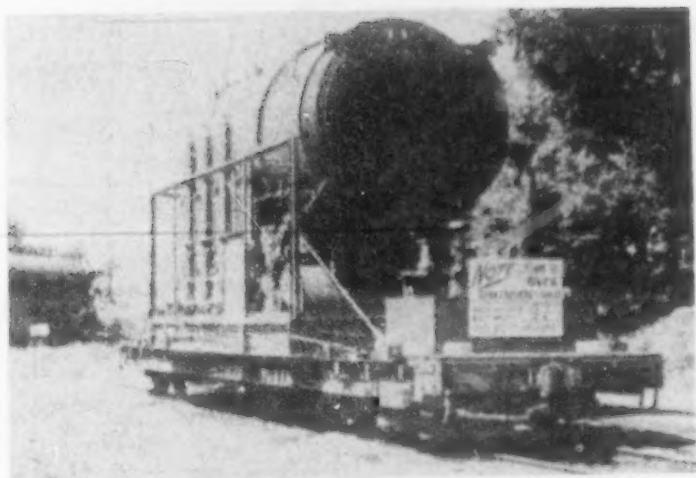


Fig. 2. A 50,000 lb/hr. 300 psig steam Fluidfire Firtube Boiler being delivered to a major food processor.

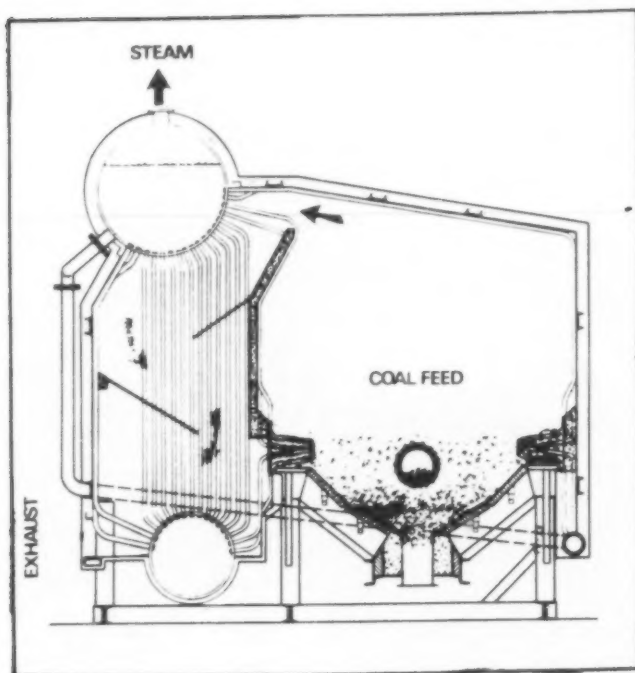


Fig. 3. Fluidfire Package Watertube Boiler Design

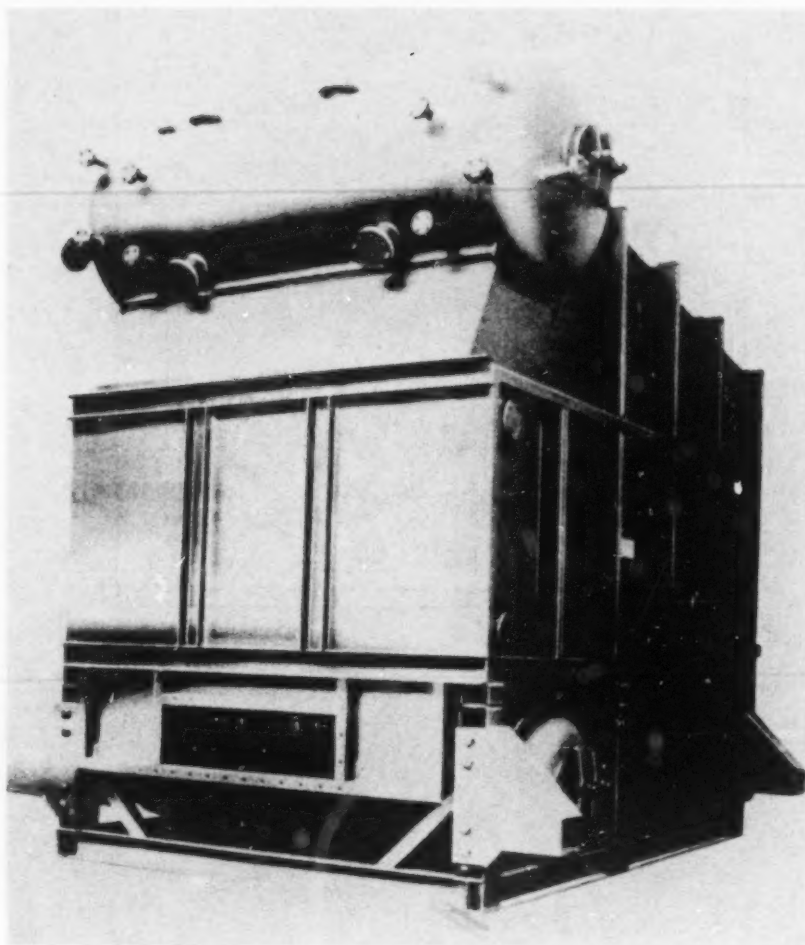


Fig. 4. The Fluidfire Watertube Boiler

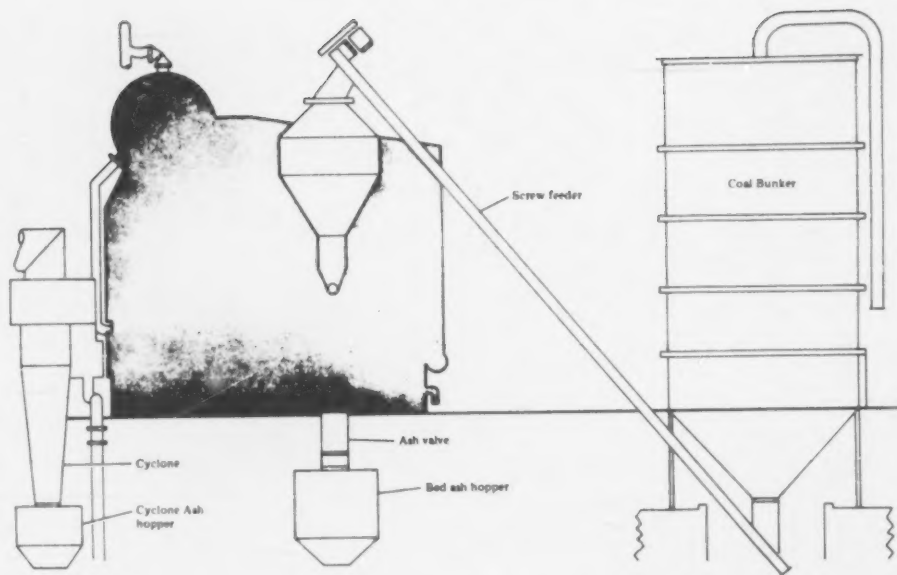


Fig. 5. The site installation of a 10,000 lbs/hr unit including a 50 ton coal hopper and automatic feeding arrangement

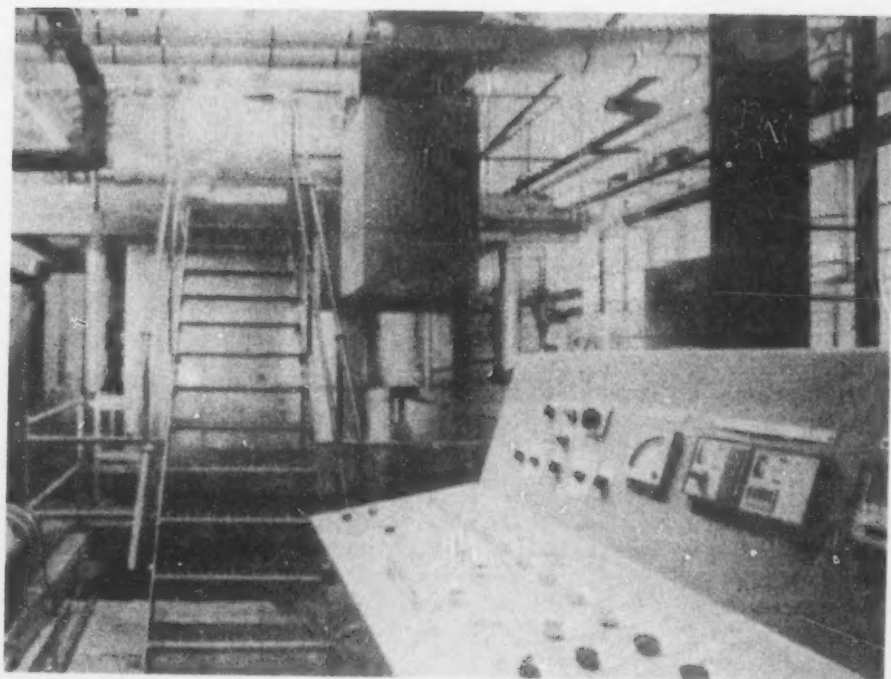


Fig. 6. The Fluidfire Watertube Boiler installed at Haywood Tylers, Keighley Factory, England.

Reprinted by permission of ENERGY USER NEWS, September 14, 1981

Fluid-Bed Unit Is First In Line Without Subsidy

By BRUCE VAIL

MARION, Ohio—After more than a year of testing, an industrial fluidized-bed boiler that the DOE calls the first to be financed entirely by private capital has begun to supply 100 percent of the steam used for process and space heating at the Central Soya Inc. soybean processing plant here.

Aware that its two 20-year-old coal-fired boilers were failing to meet environmental emissions standards, company engineers considered either converting to a boiler fueled by cleaner-burning but far costlier fuels such as oil or natural gas, or adding extensive particulate collection equipment to its existing boiler before opting for the fluidized-bed unit, according to Anthony Vince, senior engineer for Central Soya.

The fluidized-bed boiler cost Central Soya about \$1 million including installation, minor modification of the fuel feed system and addition of a bed material delivery apparatus.

Although the fluidized-bed system, manufactured by Johnston Boiler Co., Perryburg, Mich., has only cut coal consumption about 10 percent, the company has projected that the new boiler will earn back 400 percent of its "minimum earnings requirement" annually through avoided costs, Vince said.

The minimum earnings requirement, which is the formula the company uses to evaluate returns on capital expenditures, amounts to the total investment plus 17 percent, he said. The cost avoided was calculated on the basis of how much it would cost to generate the plant's steam with a natural gas-fired boiler—the least expensive alternative, Vince said.

"After carefully considering a number of options, we decided to stay with coal as our primary fuel. The problem then became how do this while meeting emissions regulations that were in effect and others that were expecting down the road. Fluidized-bed was the most economically viable answer," Vince said.

William Siskin, a spokesman for the Department of Energy's Office of Coal Utilization, said fluidized-bed boilers are now competitive with conventional coal-fired systems in terms of capital costs and cheaper than conventional units in operating costs.

Roger Barnhart, engineering manager for Central Soya, is more emphatic in his price analysis. "For a 100,000 pound standard coal-fired boiler we would have to pay more than the price of the Johnston unit on pollution control equipment alone," Barnhart said. "There is no question that fluidized bed was the way for us to go."

Savings from the improved efficiency of the fluidized-bed unit have amounted to approximately 1,000 tons of coal over the past year, Barnhart said. The new boiler system has an efficiency rating of about 85 percent, compared to 75 percent efficiency for the old units, he said.

Central Soya was anticipating the EPA's adoption of stringent sulfur dioxide emission standards in 1978 when the boiler was purchased, Vince explained, noting that since then the EPA has made those standards more stringent. The company now expects restrictions on nitrogen oxide emissions, according to Vince, but this presents no problem because the fluidized-bed unit can be easily adapted to eliminate both of these problems, he claimed.

Central Soya considered and rejected three possibilities for meeting the EPA requirements, Vince told EUN.

- First, conversion to natural gas or fuel oil firing was considered. A comparison of coal costs and oil costs from 1970 to 1978 showed costs per million Btus were consistently higher for oil, according to Vince. In addition, oil-fired boilers were rejected because of uncertain availability of the fuel, Vince said.

- Second, the engineers investigated use of a baghouse on the existing boiler system but rejected that option because Central Soya engineers were unsure that the baghouse could handle the heavy particulate emission produced by the dump grate units already in place.

Baghouses also cannot control sulfur dioxide or nitrogen oxide emissions, Vince said. Expensive scrubbers would be required for control of sulfur dioxide, he added, and nitrogen oxide emissions are extremely difficult to control after being produced in the combustion chamber.

- Third, Central Soya looked at a conventional, field-erected, coal-fired unit but decided against it because the capital cost estimates for a packaged fluidized-bed unit were lower.

The fluidized-bed boiler burns approximately 10,000 tons of high-sulfur Ohio bituminous coal annually and generates 40,000 pounds an hour of steam at 150 psig, Barnhart said. Almost all of the steam is used in industrial process with approximately 5 percent used for heating the plant, he said.

Average summer and winter demands are 20,000 lbs. per hour and 25,000 lbs. per hour respectively, and demand increases of 20 percent in a matter of ten minutes due to load swings are common, Vince said.

Sources agreed that the principal advantages of the fluidized-bed boiler over conventional or multi-fuel units are its ability to burn "dirty" or high-sulfur coal without the use of expensive scrubbers and its versatility in types of fuel the unit can use, including, biomass, industrial wastes, natural gas, oil and virtually any kind of coal.

John Wallish, sales engineer for Johnston Boiler, explained how fluidized-bed combustion works.

"The fuel is injected and burned in a bed of particles—usually limestone or sand. Water-cooled heat-transfer tubes located within the bed and surrounding water wall surfaces maintain the appropriate temperature for heat transfer and sulfur reduction."

The bed is injected with an evenly distributed flow of air, forcing the bed material upward so it is suspended in the air stream. As the speed of the air flow is increased the bed becomes highly turbulent and rapid mixing of the particles occurs. The bed takes on a fluid appearance and acts as a fluid, thus the term fluidized-bed," Wallish said.

Approximately six tons of silica sand is needed to provide the correct volume of bed material, according to Barnhart. The price of the sand is six dollars a ton, he said.

Vince reported that some unanticipated problems with sand bed material had developed in the course of the test firing. "We expected that the sand and ash in the coal itself would replenish any bed material that had been elutriated (washed away). But this didn't happen. The heat breaks the sand down into tiny particles which are blown into the baghouse. We find that when we are operating at 25,000 lbs. per hour we have to add about 500 pounds of sand a day to maintain bed level."

The boiler operators continue to experience this problem, Vince said, but since the cost of the sand is only \$1.75 a day, adding the sand is not considered a major problem, and the sand has not caused additional baghouse maintenance.

Central Soya spent \$10,000 to install a sand-feeding system, Barnhart said.

Another major problem that Barnhart and Vince experienced with the new boiler was with steam purity and water level in the drum, Vince said. By dropping the water level in the drum Vince was able to eliminate the problem of wave motion at the steam and water interface level which was causing both problems, he said.

FLUIDIZED BED BOILER

AN INDUSTRIAL APPLICATION AT CENTRAL SOYA COMPANY, INC.

MARION, OHIO

Presented to the 20th Annual Kentucky Industrial Coal Conference
University of Kentucky, Lexington, Kentucky
April 29, 1981

Presented by: A. N. Vince, Senior Project Engineer, and
R. D. Barnhart, Engineering Manager
Central Soya Company, Inc., Fort Wayne, Indiana

FLUIDIZED BED BOILER
AN INDUSTRIAL APPLICATION AT CENTRAL SOYA COMPANY, INC.
MARION, OHIO

A. N. VINCE AND R. D. BARNHART

INTRODUCTION

Central Soya's Marion, Ohio facility consists of a soybean processing plant producing degummed soybean oil, soybean meal, lecithin, and livestock and poultry feeds. A 40,000#/hr Johnston Boiler Company fluidized bed boiler, as installed at this facility, is the subject of this paper.

The work to date with this first-generation boiler has been to prove the viability of the fluidized bed combustion technology in an industrial application. Currently, no field work has been done with the addition of limestone for SO_2 retention.

Approximately 10,000 tons per year of Ohio bituminous coal are burned to generate 150 psig dry saturated steam to meet plant requirements. About 95% of the steam is used in the process for both direct contact and indirect heat exchange. The balance is used for space heating. Typical average summer and winter demands are 20,000#/hr and 25,000#/hr respectively. Load swings of 20% in 5-10 minutes are common.

WHY FLUIDIZED BED BOILER

The replaced boiler system consisted of two spreader stoker boilers with dump grates, having a combined nominal capacity of approximately 50,000#/hr. These boilers were not able to attain compliance with OEPA particulate and visible opacity regulations through the installation of mechanical collectors.

To gain compliance the following options were investigated:

1. Installation of a baghouse on the existing boiler system.
2. Installation of a field-erected, conventional-type, coal-fired boiler with particulate emission control.
3. Conversion of the existing boilers to fuel-oil firing.
4. Installation of a packaged coal-fired fluidized bed boiler with particulate emission control.

Installation of a baghouse on the existing boiler system was rejected due to the risk of bag blinding resulting from high fine carbon loading during the frequent fire cleaning operations associated with the dump grates.

The field-erected, coal-fired boiler option was rejected because preliminary capital cost estimates were much higher than with the packaged fluidized bed unit.

There were risks associated with the new fluidized bed boiler technology. However, when the Btu costs (at Marion) of fuel oil versus coal were examined from 1970 through 1978, and coupled with the uncertain future availability of fuel oil, a continued commitment to coal became imperative. (See Figure 1 for coal versus oil cost comparison.)

CONTROL PLAN

The control plan finally selected consisted of a new-technology, coal-fired fluidized bed boiler with a mechanical collector and baghouse for primary and secondary emission control. Final control plans and the application for a permit to construct were submitted in January 1979. These were subsequently approved by the director of the US EPA in July 1979.

SYSTEM DESIGN AND OPERATING SPECIFICATIONS (Flow Diagram - See Figure 2)

BOILER

- Type	Johnston Fluid Fire Series Model 2400
- Continuous capacity	40,000 lb/hr
- Operating pressure	150 psig
- Design pressure	200 psig
- Number of beds	3
- Bed temperature - coal firing	1,600°F
- Average heat transfer	7,440 Btu/hr/ft ²
- Turndown ratio	6:1 automatic control
- Air flow	25,300 ACFM
- Excess air	25%
- Outlet temperature	441°F
- Mechanical Collector, integral to boiler	36 tubes, 6-in diameter
- Fluidizing fans	(3) 30-HP
- Induced draft fan	100 HP
- Ash reinjection	Integral to rear smoke box at junction of 1st & 2nd flue gas pass

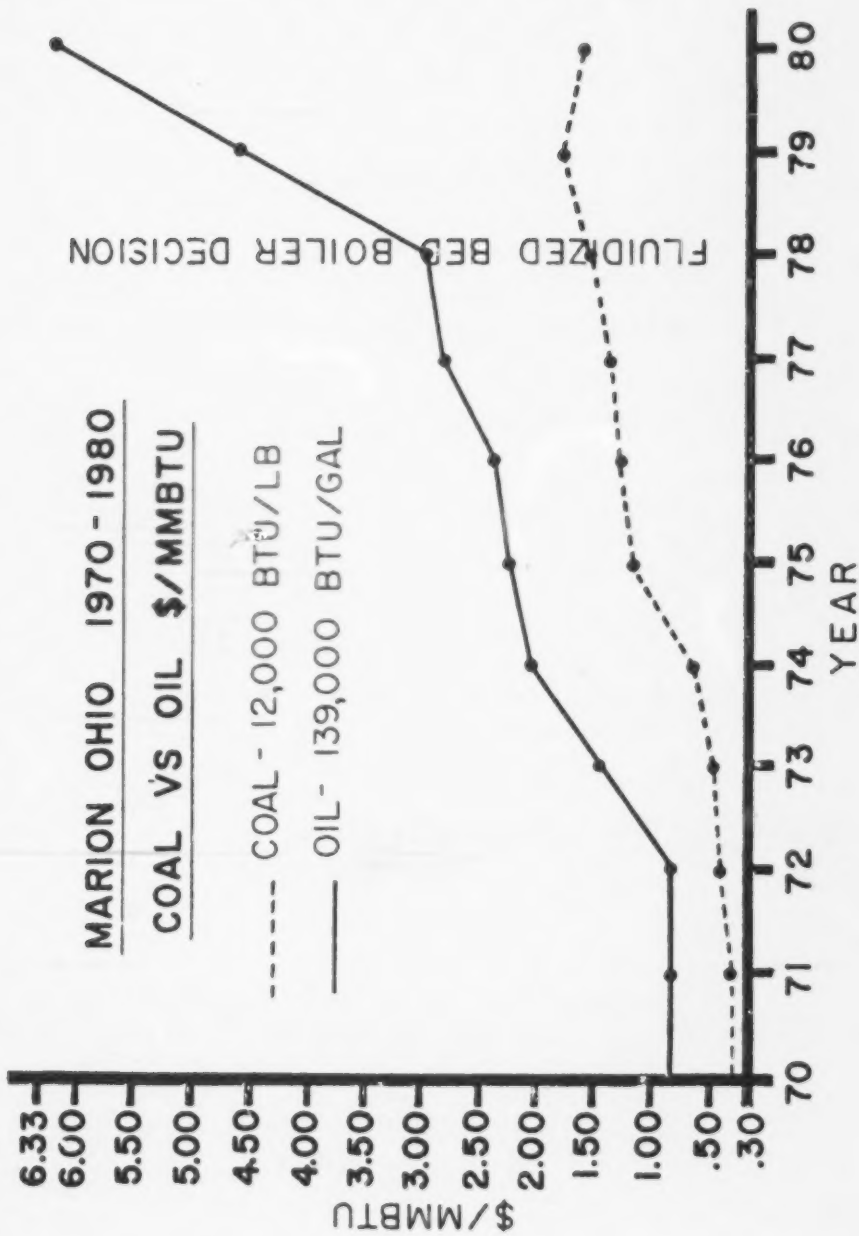


FIGURE 1

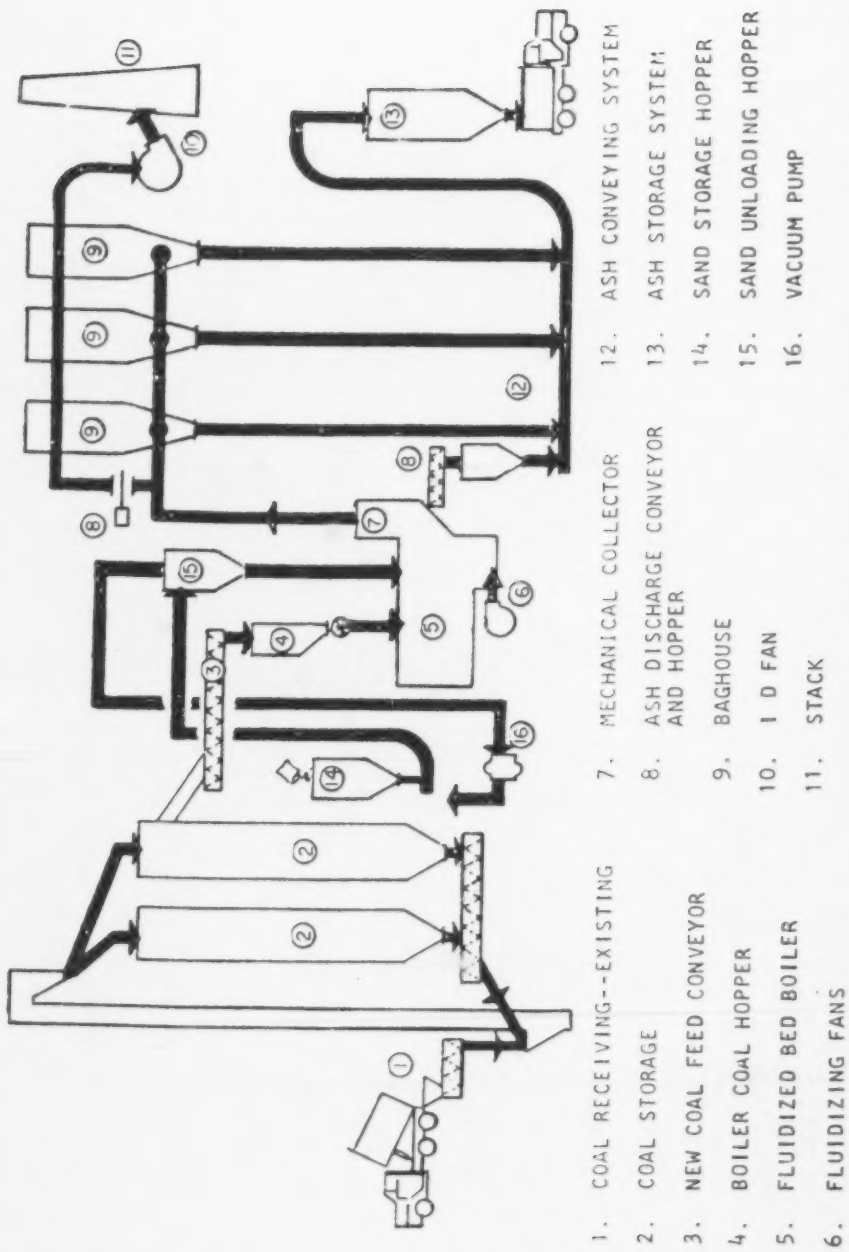


FIGURE 2

BAGHOUSE

1. System Parameters

- Gas volume 25,300 ACFM
- Gas temperature 425° F
- Operating pressure drop
flange to flange 6" wc

2. Baghouse

- Type Standard Havens
Beta Mark III, Pulse Jet
- Number of modules 3
- Total number of bags 330
- Total filter area 6,897 ft²
- Air-to-cloth ratio - gross 3.67:1
- Air-to-cloth ratio - net 5.5:1
(during cleaning)
- Design pressure + 20" wc

3. Fabric

- Type Woven fiberglass
- Finish Teflon 10%
- Weight 16.5 oz

4. Bag Support

- Cage 1" x 1/2" mesh
- Material Galvanized Steel

5. Bag Cleaning

- Compressed Air Requirements 40 CFM @ 100 psig

6. Bypass System

zero-leak guillotine damper

COAL UNLOADING AND STORAGE. Existing equipment includes a dump pit with unloading screw conveyor. This delivers coal to a bucket elevator which distributes the coal to two 200-ton capacity concrete bunkers.

No equipment additions or changes were made in this area.

COAL HANDLING TO NEW BOILER. A 12" diameter x 15' long sectional flighted screw conveyor was tied into one of the existing concrete silos. Driven by a 2-HP motor, it is set up to convey 2 T/hr of coal to a 90ft³ storage hopper on top of the boiler.

ASH HANDLING. Four new ash pickup points (one each - three baghouse hoppers and one for mechanical collector discharge hopper) were added to the existing vacuum conveying system.

BED MATERIAL HANDLING. A MAC pneumatics 7.5-HP vacuum sequencing system is used to convey bed material (silica sand at 100 lb/ft³) for selected distribution into the fluidizing beds via gravity feed through the coal feed pipes. System design capacity is 2,000 lb/hr.

ENTRAINMENT SEPARATOR. An in-line Penn water entrainment separator was installed in a horizontal section of steam outlet piping. It is designed to remove water entrained in the steam and raise the quality to American Boiler Manufacturer's Association standards of 99.5%. The collected water either drains back into the boiler or, through a level control system, flows to the deaerating heater.

SYSTEM OPERATION

PREPARATION. The boiler must first be loaded with bed material. It requires approximately six tons of silica sand, 12 to 18 mesh, to bring the static bed height up to approximately 18" above the nozzles. When up to temperature, the fluidizing height increases to approximately 30" above the horizontal plane of the nozzles. A 5" bed depth below the nozzles remains static to provide distributor plate insulation.

The boiler is started up on natural gas. The natural gas is introduced to each bed by a typical Factory Mutual-approved modulating gas train. It enters the bed through the bed nozzles where it mixes with the combustion/fluidizing air. Plenum air pressure is approximately 18-22" wc.

START-UP. From a completely cold start, i.e., ambient temperature water and new moisture-laden bed material, it takes approximately three hours to bring all three beds up to 1,400° F. This is the minimum temperature we have set for coal firing. Once this temperature is reached and coal firing begins, the flow of natural gas is automatically discontinued.

Our present boiler room natural gas supply of approximately 20,000 SCFH enables us to only fire two beds concurrently during this start-up process. We believe, with increased capacity to 40,000 SCFH, this cold start-up time could be significantly reduced.

RUNNING - AUTOMATIC MODE. Steam pressure is maintained by the incorporation of a proportioning-type combustion control system with

lead/lag capabilities. Coal fuel feed devices are modulated as steam demand dictates. Further turndown is accomplished by automatically turning beds off. A 4:1 turndown with coal firing and 6:1 firing natural gas can be achieved on automatic control.

An induced draft fan outlet damper is modulated to maintain firebox pressure at about -0.5 in wc. The system provides feed-forward control to handle large firebox pressure fluctuations associated with beds coming on and off.

SUPPORT SYSTEMS:

Mechanical Collector. A continuous bottom ash removal system from the mechanical collector deposits ash into a 78-ft³ effective volume hopper. A high-level probe indicates the need to evacuate ash. The boiler operator manually initiates ash removal via the vacuum conveying system. Typically, with average loads of 25,000#/hr, the hopper requires emptying every six hours.

Baghouse. The baghouse system uses a programmable controller to monitor and sequence its system operations. At loads of 25,000#/hr, flange-to-flange pressure drop increases from 2" wc after cleaning to 6" wc in about eight hours. System cleaning can be initiated by either pressure drop or a timer. The hoppers are evacuated following each cleaning cycle in the same manner as previously outlined for the mechanical collector hopper. Compressed air pressure for bag cleaning is set at 80 psig.

Sand Handling. The boiler operator manually fills a 500-lb storage hopper from 100-lb sacks of sand. A vacuum sequencing unit is turned on and material is drawn through a 2" conveying line approximately 50 total feet to just above the elevation of the boiler coal hopper. Sand is delivered to each of the beds through the coal feed pipes by means of air-cylinder-operated diverter valves.

SYSTEM OPERATIONAL PROBLEMS

STEAM PURITY AND WATER LEVEL. The system was first put into operation in May 1979 and, to date, has accumulated approximately 2,000 hours of operation.

The first problems encountered were water entrainment in the steam and erratic drum water level. These problems appeared to be linked. Water level in the drum was being carried high, and there was insufficient volume in the steam space for internal mechanical separation equipment. In addition, we believe that the orientation of the in-bed heat transfer tubes, which have a very high heat transfer rate, were conducive to setting up steam and water flow currents that resulted in wave motion at the steam and water interface in the drum.

To solve these problems, the following steps were taken:

1. The water level in the drum was dropped approximately six inches to increase steam space. To accomplish this, two rows of tubes in the convection section were blanked off.

2. Some internal steam baffle changes were made.
3. A two-element feedwater control system was added.
4. An external water entrainment separator was added.

These changes resulted in a stable drum water level and a 99.5% steam purity level under continuous operating conditions which have ranged up to 36,000#/hr. We conclude the reduction in convective heat transfer surface has not infringed on boiler output capacity.

SAND USAGE. It was optimistically expected that sand usage would be at a minimum. The ash and sand in the coal was expected to replenish any bed material that had been elutriated. In practice, this is not the case. When operating at steam loads of 25,000#/hr, approximately 500 lb/day of sand must be added to maintain bed level. Bed level is monitored by visual inspection through sight ports and by observing bed fluidizing air pressure gauges. Improvements in the area of bed level monitoring need to be made. This usage resulted in the need for the previously mentioned sand-handling system.

BED DEFLUIDIZATION:

Nozzle Back Feeding. Investigation of a loss of bed pressure and the appearance of bed sluggishness resulted in discovering sand in the air distribution plenums of the two outside beds. Each of the two outside beds have hinged flapper-type check valves between the fluidizing fans and air distribution plenums. These check valves were found to be sealing improperly, allowing air to back-flow through the nozzles when the outside beds were off as steam demand dictated. Bed material was being carried into the plenums with the air flow through the nozzles. This created improper air distribution to the nozzles.

Fused Sand Formation. The original bed design incorporated a dead space between the center and two outside beds. Over a period of time, due to lack of air for fluidization the bed material fused together. At times of high turndown when the center bed is firing only on natural gas, this fused sand formation directed the gas flame down toward nozzles in rows immediately adjacent to the two outside rows of the center bed, resulting in burned off nozzles. Thirty-nine nozzles have been damaged in this fashion. There are a total of 576 nozzles in the three beds.

Erosion. By surface micrometer measurements, it is estimated that erosion has removed approximately 0.035" of material from a total area of about 10 ft² in the front and rear fourth of the side water walls adjacent to #2 and #3 beds. It appears the erosive action took place from the top down.

To solve these three bed defluidization problems, the following corrective actions are being taken.

1. The dead spots between beds are being filled with refractory material to a height of approximately 13 inches.
2. The two outside rows of nozzles in each bed (total of 48 per bed) are being removed. Some selected holes in other nozzles are being seal-welded. This will increase pressure drop across the bed distributor plate, thus increasing fluidizing velocity from a present estimated 10 fps to a minimum 12 fps. Distribution plenum pressure will increase from present 18-22" wc to 24-28" wc.

Since the far outside nozzle rows on #2 and #3 beds will be eliminated, a properly sloped refractory wall will be constructed for permanent attachment to the water wall.

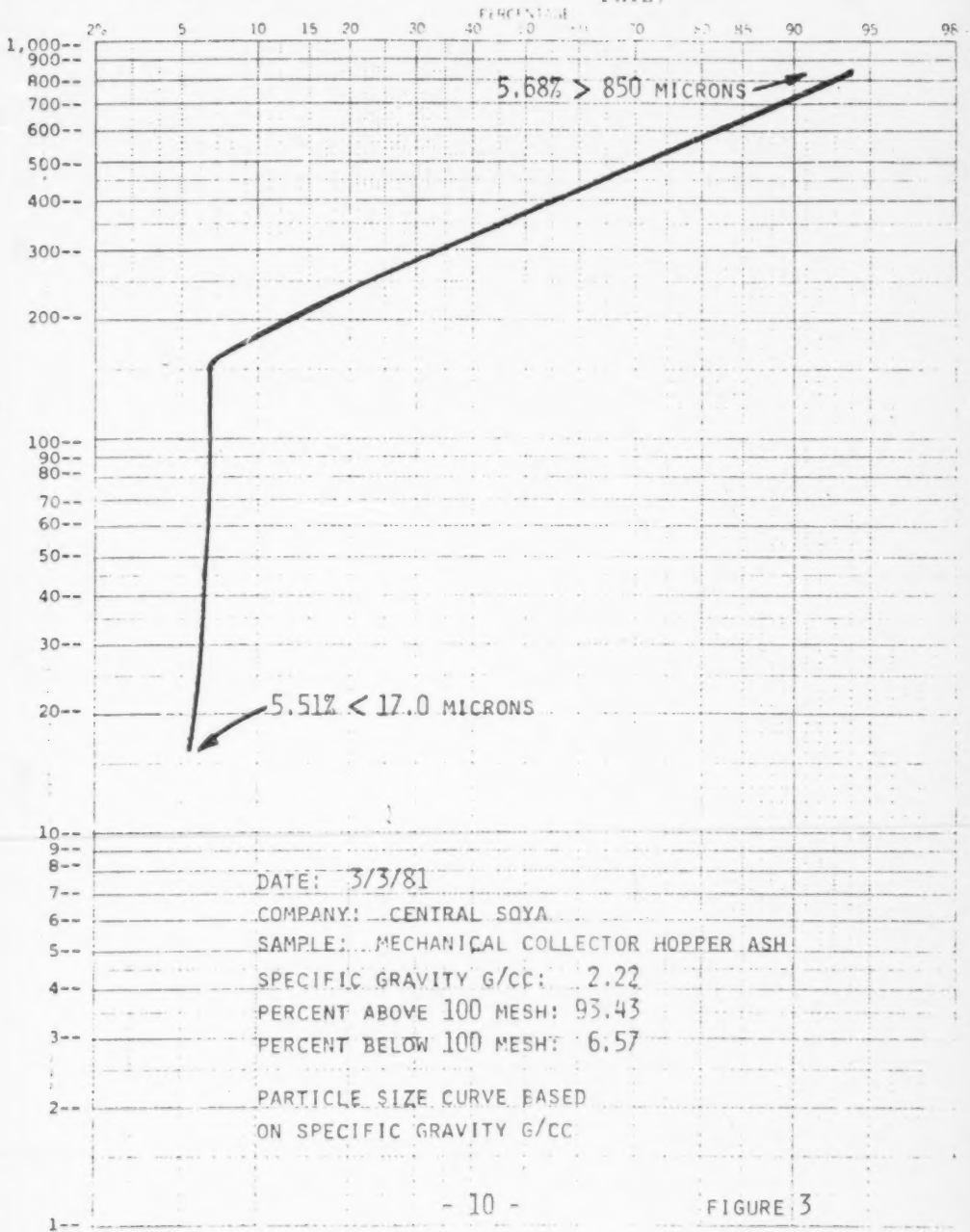
3. An improvement will be made to the air distribution plenum check valves of beds #2 and #3. It will consist of a hinged plate with a motorized operator properly interlocked with the combustion control system. A raised seat for positive shutoff will also be provided.
4. A 1" pipe and hand-operated ball valve will be piped from the air distribution plenum of #1 bed to both #2 and #3 beds. This is intended to keep pressure on the two outside beds to prevent sand back-flow at times when those beds are off as steam demand dictates.
5. We believe that the erosion was precipitated by improper air distribution and that once proper distribution is established and maintained, erosion will stop. To monitor erosion in previously mentioned areas, some measured test coupons of the same boiler plate material have been installed.

SYSTEM PERFORMANCE

On February 25, 1981, stack emission tests were conducted on the system. Four test repetitions were run. The first three tests were conducted with the baghouse on line. Particulate, SO_2 , and NO_x emissions were determined by EPA methods. Boiler efficiencies were calculated by using ASME abbreviated efficiency test procedures. Particulate and SO_2 emissions were determined in the fourth test. Proximate and ultimate coal analyses were determined on a composite coal sample extracted during the tests. Ash samples were taken from the mechanical collector and baghouse hoppers. These were analyzed for combustibles. Particle sizing was done on those ash samples, and the particulate catch in the stack during the fourth test. (See Figures 3, 4, and 5.)

BAHCO ANALYSIS
PARTICLE SIZE DISTRIBUTION

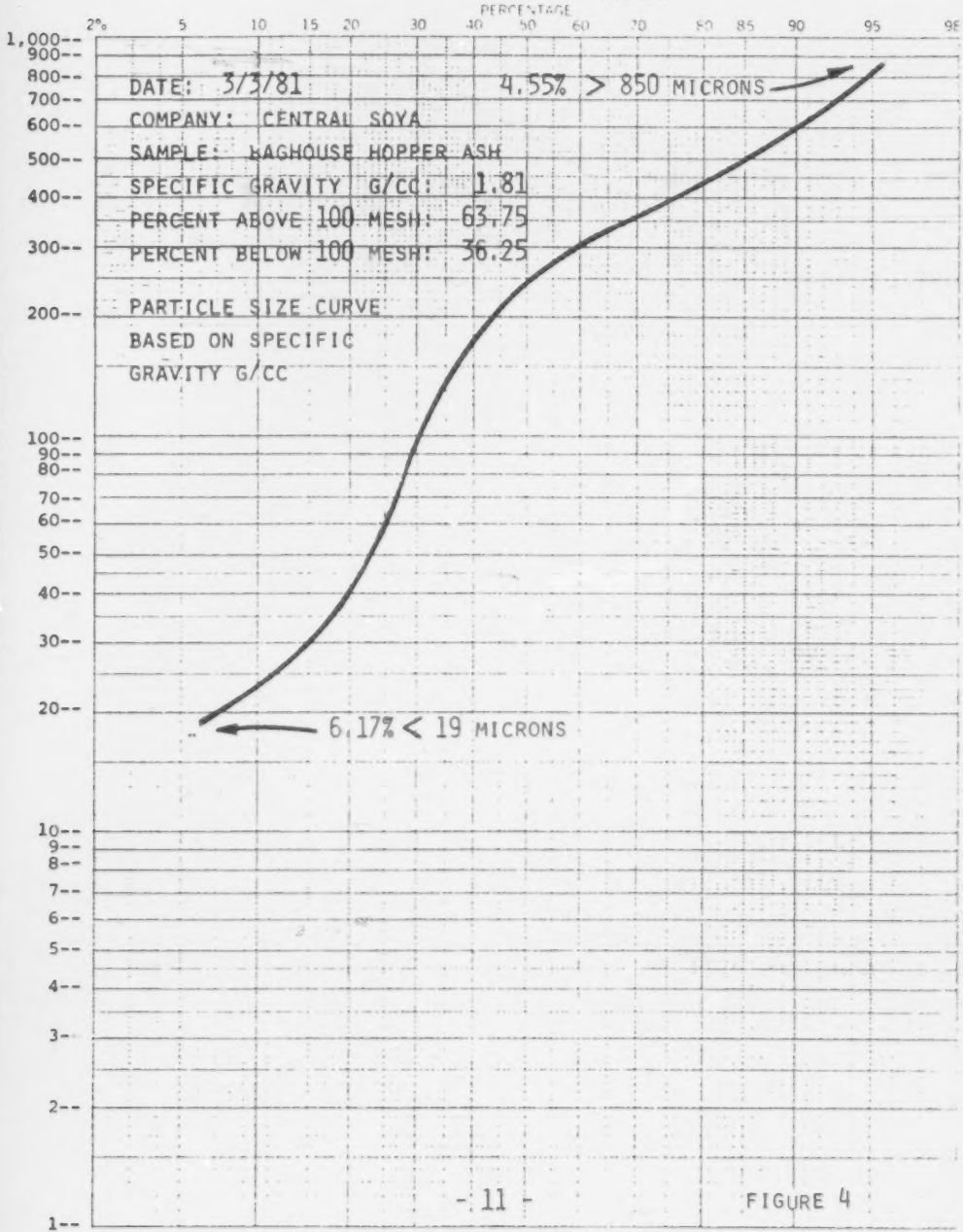
SAMPLE:
COMPANY:
DATE:



CUMULATIVE & LESS THAN STATED SIZE

BAHCO ANALYSIS
 PARTICLE SIZE DISTRIBUTION

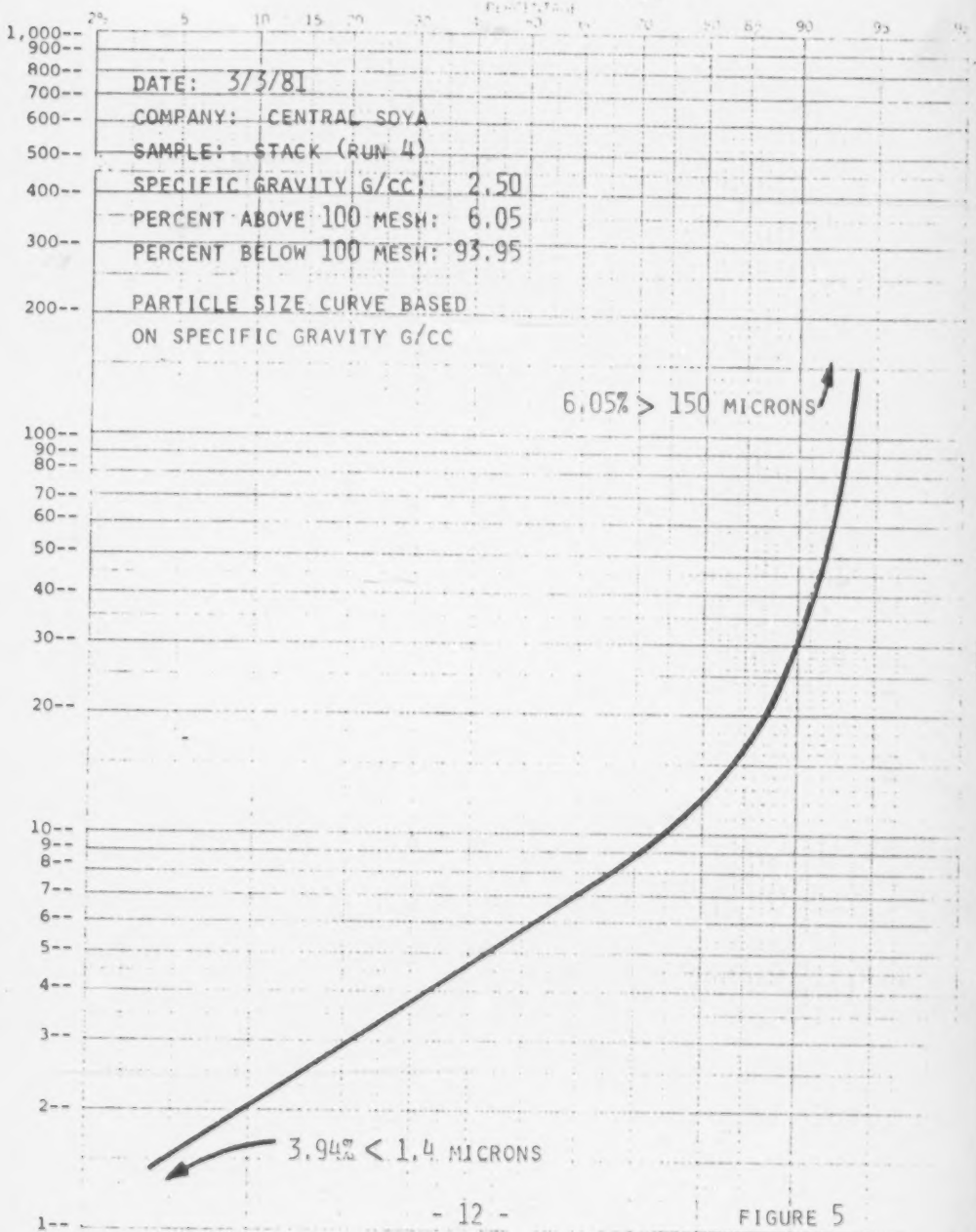
SAMPLE:
 COMPANY:
 DATE:



CUMULATIVE % LESS THAN STATED SIZE

BAHCO ANALYSIS
PARTICLE SIZE DISTRIBUTION

SAMPLE:
COMPANY:
DATE:



CUMULATIVE & LESS THAN STATED SIZE

The following details the coal analyses, and provides a table of actual versus design and EPA-allowable test results.

COAL ANALYSES

COAL SPECIFICATION: Ohio bituminous, modified stoker grade, screened and thermally dried with 85% 1-1/4" x 1/4" and 15% - 1/4" to 0.

Proximate Analysis

	<u>As Received</u>	<u>Dry Basis</u>
% Moisture	10.28	-----
% Ash	7.17	7.99
% Volatile	37.38	41.66
% Fixed Carbon	<u>45.17</u>	<u>50.35</u>
	100.00	100.00
Btu/lb	12085	13470
% Sulfur	3.49	3.89

Ultimate Analysis

	<u>As Received</u>	<u>Dry Basis</u>
% Moisture	10.28	-----
% Carbon	66.39	74.00
% Hydrogen	4.63	5.16
% Nitrogen	1.20	1.34
% Chlorine	0.14	0.16
% Sulfur	3.49	3.89
% Ash	7.17	7.99
% Oxygen (diff)	<u>6.70</u>	<u>7.46</u>
	100.00	100.00

Fusion Temperature of Ash

	<u>Reducing Method</u>
Initial Deformation	2000° F
Softening (H = W)	2220° F
Softening (H = 1/2W)	2250° F
Fluid	2390° F

	Test 1	Test 2	Test 3	Test 4	EPA Allowable	System Operating Design
Baghouse in Service	Yes	Yes	Yes	No	----	----
Steam Flow lb/hr ¹	36050	35667	35865	34755	----	40000
Steam Pressure psig	150	151	153	152	----	150
Flue Gas Exit Temp. °F	432.5	434.5	433.3	431	----	441
#1 Bed Temp. °F	1720	1720	1710	1710	----	1600
#2 Bed Temp. °F	1740	1730	1740	1730	----	1600
#3 Bed Temp. °F	1740	1710	1730	1740	----	1600
Excess Air - %	25.1	26.4	29.9	25.6	----	25
ACFM ³	25300	25330	25630	24810	----	25300
Boiler Heat Loss Eff.-%	83.73	83.57	83.46	----	----	78.65
Particulate Emission						
lb/10 ⁶ Btu ("F" Factor)	0.0311	0.02805	0.01353	0.9441	0.374	0.230
SO ₂ Emission						
lb/10 ⁶ Btu ("F" Factor)	3.298	2.885	----	3.078	6.1	1.2 ²
NO ₂ Emission						
lb/10 ⁶ Btu ("F" Factor)	0.6103	0.6696	0.6831	----	----	0.70
Heat Loss - Combustible in refuse Btu/lb as fired fuel	327.7	327.7	327.7	----	----	----

¹Includes approximately 10,000#/hr vented through muffler

²Based upon limestone addition

³Includes leakage from non-operating boiler connected to test stack

An interesting aspect of the results is the fact that much of the coal sulfur does not appear in the stack gases. Theoretically, if all the sulfur in the coal was emitted as SO₂, the emission would be 5.78 lb/10⁶ Btu, with a coal Btu content of 12,085 Btu/lb. Actual average emission was about 54% of theoretical with no limestone addition. Similar data obtained during emission testing of the 55,000#/hr spreader stoker boiler at our Delphos, Ohio facility yielded SO₂ emissions equal to theoretical. Apparently, the sulfur is retained in the fluidized bed.

PROJECT CAPITAL COST

The capital cost for the project as outlined above will be approximately \$1 million at completion.

CONCLUSION

The Marion installation has demonstrated that a fluidized bed boiler has good application to medium-sized industries. Operational problems which have been experienced are to be expected in any new design, and solutions can probably be found. Four significant advantages over a conventional coal-fired unit seem to be the lower capital cost of the packaged design, an increased boiler efficiency, low NO_x emissions, and a low SO₂ emission factor.

Central Soya is currently investigating fluidized bed units for replacement of large, gas/oil-fired boilers at another location.

ACKNOWLEDGEMENTS

Acknowledgement is gratefully made to colleagues at Central Soya Company, Inc., Marion, Ohio; Johnston Boiler Company, Ferrysburg, Michigan; and others too numerous to mention, who have supported and worked painstakingly throughout the development of this project.

ANV/RDB:04/10/81
dc:62.30

A. N. Vince and Roger D. Barnhart - Central Soya Company, Inc.

This paper presented at Industrial Coal Conference, University of Kentucky, April 29-30, 1981

○